COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

Boston Gas Company d/b/a KeySpan Energy Delivery New England	)	D.T.E. 03-40

INITIAL BRIEF OF
BOSTON GAS COMPANY d/b/a
KEYSPAN ENERGY DELIVERY NEW ENGLAND

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I. INTRODUCTION

In this proceeding, the Department of Telecommunications and Energy (the "Department") is reviewing a request for approval of performance-based rates under G.L. c. 164, § 94, which was filed on April 16, 2003 by Boston Gas Company d/b/a KeySpan Energy Delivery New England ("Boston Gas" or the "Company"). The Company's performance-based ratemaking plan ("the PBR Plan") involves two primary components: (1) the establishment of cast-off distribution rates under traditional cost-of-service ratemaking principles to recover an operating revenue deficiency of $61,999,247[1] Exh. KEDNE/PJM-2 [rev.2]); and (2) the commencement of a proposed price-cap formula to adjust rates over the five-year time period of the PBR Plan.

Under G.L. c. 164 § 94, the rates charged to customers for utility gas service are set by the Department, which bears the authority and responsibility for ensuring that the utilities under its supervision provide safe, reliable and least-cost service to

1 As set forth in the Company's filing, the Company collected revenues in 2002 of $612,204,751 to cover operating expenses of $674,203,998. Exh. KEDNE/PJM-2 [rev. 2], at 2, 4.

Massachusetts consumers. G.L. c. 164, § 94; see, Incentive Regulation, D.P.U. 94-158, at 3 (1995) ("D.P.U. 94-158").[2] In a ratemaking proceeding undertaken by the Department pursuant to G.L. c. 164, § 94, the Company is permitted to recover the cost of providing service to its customers, including a fair and reasonable return, provided that the Company demonstrates to the Department that its operating costs are reasonable and prudently incurred on behalf of customers.[3] To determine whether the Company has made this demonstration, the Department conducts an investigation, develops an extensive factual record and applies law and well-established ratemaking principles. In this Initial Brief, the Company sets forth the evidentiary facts and ratemaking precedent supporting the recovery of its $62 million revenue deficiency and responds to the issues raised in the initial briefs of the intervenors.

As an initial matter, however, the Company must respond to a number of claims made by the Attorney General that are designed more to impugn the motives and reputation of the Company's management than to put forth a systematic and meaningful examination of the Company's rate proposal. These claims misrepresent a number of issues relating to the Company's finances and operations, are irrelevant to the Department's ratemaking process, are unwarranted given the Company's strong commitment to its customers. Most importantly, and as demonstrated below, these claims are not supported by law, precedent or facts in the evidentiary record. As a result, these claims offer little assistance to the Department in terms of fulfilling its statutory obligation to investigate and determine the propriety of the Company's proposed rates

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2 As affirmed by the Supreme Judicial Court, in e.g., Massachusetts Electric Co. v. Department of Public Utilities, 643 N.E.2d 1029, 419 Mass. 239 (1994); Boston Edison Company v. City of Boston, 459 N.E.2d 1231, 390 Mass. 772 (1984).

3 American Hoechest Corp. v. Department of Public Utilities, 399 N.E.2d 1, 379 Mass. 408 (1980).

under G.L. c. 164, 94. None of these claims should be given any credence by the Department.

For example, the Company's request is neither unusual in its existence or its size, nor is the Company's request in any way improper (Attorney General at 2). The Company is the largest gas utility in the state, serving over 575,000 customers with annual operating revenues of $600 million. Therefore, the amount of the increase is as much a function of the size of the Company's operations and the length of time that has elapsed since the Company's last rate case than any other factor. However, in terms of cost drivers, the record shows that there are three primary factors driving the need for the increase: (1) inflation in base operations and maintenance ("O&M") expense since 1996; (2) increased investment in the distribution-system infrastructure to meet safety and reliability requirements; and (3) increased pension expense. Exh. KEDNE/JFB-1, at 4, 34-35; Exh. KEDNE/PJM-1, at 14-16, 44; Exh. AG-4-16; Exh. AG-6-30. Increases in O&M expenses and system investment are unavoidable over time because the Company's distribution system is the second oldest in the U.S and is composed of a relatively large amount of cast-iron main that is required to be replaced for system-reliability purposes. Exh. DTE-4-41; Exh. DTE-4-43; RR-AG-44.

In addition, to maintain the system, the Company employs hundreds of skilled workers in a relatively expensive labor market, and in fact, over one-half of the revenue deficiency is resulting from increases in the cost of employee wages and benefits. Exh. KEDNE/JFB-1, at 22. Wages and salaries represent approximately 49 percent of the Company's annual O&M expense, and total compensation constitutes about 66 percent, which means that the Company's overall expense levels are substantially affected by wage increases that are typically greater than the rate of inflation.[4] Still, including the base-rate increase granted by the Department in 1996, the Department has allowed the Company's base revenues to increase by only $20 million in the past 10 years.[5] This represents an increase in the Company's total 1993 revenue requirement of only three percent and an increase in the base rates of Boston Gas of less than 7 percent of the ten-year period 1993-2003.[6]

The Company does not dispute the Attorney General's statements that the high cost of energy is one of the critical economic issues confronting the citizens of Massachusetts or that gas consumers are "struggling to pay ever-increasing heating bills" (Attorney General at 2, 4). It is especially difficult in times where increasing gas commodity costs, which are beyond the Company's control, combine with increasing operating and maintenance costs to push the overall price of natural gas service higher. Although the Attorney General fails to mention it, the Company's filing incorporates three elements to mitigate the impact of the rate increases on customers, which are to:

- Limit the impact of any base-rate increase to no more than 10 percent for the average customer in each rate class as compared to the 2002 total bill by delaying the portion of the increase that would cause the bill impact to exceed 10 percent. The Company would not recover any revenues lost in the interim period of the delay; Exh. KEDNE/JFB-1, at 3; AG-23-23.
- Expand eligibility for the low-income rate to allow customers with annual incomes up to 200 percent of the poverty level to be eligible for the low-income rate, as compared to the 175 percent threshold included in current rates; Tr. 3, at 366.

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4 It is difficult to have it both ways. The Attorney General decries the impact of the rate increase on customers and then argues to the Department that it should deny the Company's PBR Plan because the Company has reduced staffing levels since 1997 (Attorney General at 114-118).

5 The Company's last request for base-rate relief prior to D.P.U. 96-50 was in 1993 in Boston Gas Company, D.P.U. 93-60 (1993). In D.P.U. 96-50, the Department granted a base-rate increase of approximately $8 million, and over the first term of the PBR Plan (1996-2002), the Company was allowed additional revenues of $11 million. Exh. MDFA-3-8.

6 The Company's non-gas cost base rate revenue requirement from D.P.U. 93-60 was $287,942,802 versus a total revenue requirement including gas costs of $645,639,876. D.P.U. 93-60, at 490, Schedule 1.

- Supplement the low-income rate with a new “On Track Program” for low-income customers, which provides budget management support and arrearage forgiveness. The Company plans to implement this program at no cost to consumers. Exh. KEDNE/JFB-1, at 13-15; MCP-2-12.

There will never be a time that a cost increase is “easy” for the Company’s customers to absorb. However, it remains the Company’s obligation to ensure, to the best of its ability, that it maintains access to the capital resources necessary to serve customers safely and reliably, without “burdening” its customers with unwarranted costs. There comes the occasion, therefore, when moderate increases in base rates, while undesirable, are both necessary and appropriate.

Other claims made by the Attorney General that are equally misguided, misleading or unsupported by law, precedent or evidence in the record are as follows:

- <u>The record does not support the claim that the Company failed to adequately maintain its system (Attorney General at 2-3)</u>;

There is no evidence that the Company’s “failure to prevent leaks” or system deterioration led to low system-pressure on 1500 streets, nor is there any evidence cited by the Attorney General. In fact, low pressure results from increased load on the system and is <u>not</u> related to leaks or leak repair. The record shows that an increased number of low-pressure points (<u>i.e.</u> the 1500 streets) were detected on the Company’s system beginning in 2000 because of a significant upgrade of the Stoner Model engineering system in 1999, which enabled the Company to evaluate system pressure on a more localized basis than it had in the past. <u>See</u> <u>e.g.</u>, RR-AG-49; RR-AG-50; RR-AG-76. Also, there is no evidence that there was a consistent increase in the number of leaks or leak repairs over the PBR period.

The Attorney General does not mention that, since the inception of the first PBR Plan (1996 through 2002), the Company has been subject to a comprehensive service-quality program. The Company has met or exceeded all performance thresholds over the term of the PBR Plan, and incurred no penalties, with the exception of the very first year of the plan’s operation (which therefore could not be the result of any deterioration in service over the term of the PBR Plan).[7]

- <u>The record does not support the claim that the Company has “loaded the test year to bring the distribution system back up to standard”</u> (Attorney General at 3);

[7] All of the Company’s service-quality filings were provided in this docket in Exhibit AG-22-16.

Under state and federal law, the Company must replace segments of its distribution system to ensure safe and reliable operation. The record shows that, since acquiring Boston Gas, KeySpan has invested consistent amounts of capital in all three years of its ownership (2000-2002). The record also shows that this investment level will increase in the future, although future investment will not be reflected in the rates being set in this proceeding. See, e.g., Exh. AG-18; Exh. DTE-4-19.

In addition, under standard Department ratemaking precedent, all capital investment in place through the test year is eligible for inclusion in rates in a base-rate proceeding, regardless of when it is invested. In this case, this means that rates will be set to include all amounts invested by the Company in each year leading up to and including 2002, and therefore, it is irrelevant whether the Company's capital investment is made in equal payments over that period, or all in one year.

- The merger between KeySpan Corporation and Eastern Enterprises did not require review or approval by the Department, and there is no record support for the claim that the merger has resulted in increased costs (see Attorney General at 3).

Under Massachusetts law, the Department has authority to review and approve mergers or acquisitions only between regulated companies. G.L. c. 164, 96. Neither KeySpan nor Eastern Enterprises is regulated by the Department, and therefore, the Department did not have jurisdiction to review or approve the merger. Moreover, there is no record support for the claim that KeySpan's acquisition of Eastern Enterprises has resulted in increased costs or "harm" to Boston Gas customers, nor is any evidence cited by the Attorney General. In fact, the record shows that the Company did share in merger benefits with over $55 million achieved by KeySpan in the first two years following the merger. Tr. 22 at 2770-2790. Although Boston Gas customers shared in those savings, the Company has not sought any recovery of merger costs. The Attorney General's claims are based entirely on the fact that Boston Gas is not required to allocate non-incremental corporate-management costs to its affiliates, Colonial Gas Company and Essex Gas Company (see, e.g., Attorney General at 3). This cost-allocation policy was settled by the Department in the Colonial and Essex merger cases[8] and would be effective in this case, whether or not KeySpan had acquired Eastern Enterprises.

- No Department approval is required to establish and operate under a service-company structure (see Attorney General at 4).

[8] Eastern-Essex Acquisition, D.T.E. 98-27 and D.T.E. 98-27-A (1998) and Eastern-Colonial Acquisition, D.T.E. 98-128 (1999).

The Securities Exchange Commission ("SEC"), and not the Department, has authority over KeySpan in terms of the establishment of the Service Company.[9] As a registered public-utility holding company under the Public Utilities Holding Company Act of 1935 ("PUHCA"), KeySpan is required by federal law to establish a centralized service company to provide shared services to its affiliates, and to ensure the fair and appropriate assignment of costs to the affiliates benefiting from the shared services. There is no statute or precedent requiring KeySpan to obtain the Department's approval for the establishment of the Service Company, nor is any requirement cited by the Attorney General. Under Massachusetts law, KeySpan is required only to file its affiliate contracts for informational purposes with the Department. The Attorney General cites no legal basis for his claim that this arrangement required the Department's approval.

- <u>No Department approval is required to outsource the gas-resource portfolio or to purchase gas for a period of less than one year</u> (Attorney General at 4).

Under Massachusetts law, the Company is required to obtain the Department's approval of gas-supply contracts in excess of one year. G.L. c. 164, 94A. There is no statutory requirement to obtain approval of an asset-management contract that does not involve the purchase of gas. The record shows that the Company's contract with Entergy-Koch Trading, LLP involves two components: (1) a three-year asset management commitment; and (2) a one-year gas-purchase arrangement, which is typical gas-purchase period for local distribution companies operating in the Commonwealth. Therefore, the Department's approval was not needed for this contract. Exh. AG-17-46. The Attorney General cites no legal basis for his claim that this contract required the Department's approval.

- <u>No Department approval is needed in relation to the merger debt recorded on the Company's books</u> (Attorney General at 4).

Under Massachusetts law, the Company is required to obtain the Department's approval of any issuance of long-term debt. G.L. c. 164, 14 and 16. The record shows that $650 million in merger-related debt was recorded on the Company's books for financial reporting purposes consistent with generally accepted accounting principles ("GAAP"), a result of the merger and the related acquisition premium. Exh. AG-4-13. In addition, this merger-related debt and the interest costs associated with the debt are <u>not</u> included in the cost of service for Boston Gas. The Attorney General cites no legal basis for his claim that this arrangement required the Department's approval.

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[9] The Attorney General acknowledges that under PUHCA: (1) the SEC had jurisdiction to approve the KeySpan/Eastern Enterprises merger; (2) the SEC has jurisdiction to approve the creation of the Service Company; (3) in approving the merger, the SEC is required to find that the utilities being acquired cannot be operated as independent entities without the loss of substantial economies that would be secured through a service company; and (4) the SEC performs audits of the Service Company to ensure compliance with SEC guidelines (Attorney General at 20, fn.11, <u>citing</u> RR-AG-15, Attachment (a), page 15.

- The record does not support the claim that the Company has recorded costs on the Company's books of account contrary to the Uniform System of Accounts for Gas Companies (Attorney General at 4).

The Attorney General makes no reference as to the specific circumstances to which he is alluding, nor does the Attorney General cite to any record evidence to support his claim. The Company recorded all costs in accordance with the Department's Uniform System of Accounts, as shown on the Company's 2002 Annual Return to the Department.

The Department should disregard the misleading and unfounded claims of the Attorney General and should evaluate the Company's proposal in terms of the facts on the evidentiary record and the law and ratemaking practices and precedents applicable to those facts. In that regard, the Company has demonstrated that the costs for which it seeks recovery are: (1) reasonable and prudently incurred on behalf of customers; and (2) are supported by evidence in the record showing that cost recovery is warranted and consistent with Department precedent.

The remainder of the Company's Initial Brief is organized as follows: Section II reviews the procedural background of the case. Section III discusses the Company's cost-of-service proposals, including rate base, revenue adjustments, post-test year adjustments, cost of capital and capital structure. Section IV sets forth the Company's rate-design proposals and Section V discusses the Company's PBR proposal. Section VI addresses Staffing Levels and Section VII covers the Company's proposals on the Weather Stabilization Clause and the Pension Reconciliation Adjustment Mechanism.

II. PROCEDURAL BACKGROUND

On April 16, 2003, Boston Gas submitted for approval by the Department revised schedules of rates (M.D.T.E. Nos. 1209 through and including 1225) to become effective on May 1, 2003. Also on April 16, 2003, the Attorney General of the Commonwealth of Massachusetts intervened as of right pursuant to G.L. c. 12, § 11E, and commenced discovery upon the Company's case. As filed, the Company's proposed rate schedules are designed to produce increased total annual revenues in the amount of $61,304,367, which represents a 9.59 percent increase in the total bill for the average customer as compared to current rates.[10] The Company's proposed rates are based on a test year ending December 31, 2002.

The Department suspended the effective date of the proposed rate tariffs until November 1, 2003 and opened an investigation into the Company's proposed base rates and PBR Plan, as allowed by G.L. c. 164, § 94. The Department conducted public hearings at its offices and in the municipalities of Acton, Lynn, Quincy and Boston, Massachusetts on May 19, May 20, May 21 and May 22, 2003, respectively.

On May 23, 2003, the Department conducted a procedural conference to establish a schedule for discovery, evidentiary hearings and briefs. At the procedural conference, the Department granted the petitions to intervene of: Bay State Gas Company ("Bay State"), the Berkshire Gas Company ("Berkshire"), the Massachusetts Division of Energy Resources ("DOER"), Massachusetts Community Action Program Directors Association, Inc. ("MASSCAP"), Massachusetts Oilheat Council, Inc. ("MOC"), Massachusetts Alliance for Fair Competition, Inc. ("Alliance"), Associated Industries of Massachusetts ("AIM"), Massachusetts Development Finance Agency and the United Steel Workers of

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10 On May 7, 2003, the Company submitted certain revised exhibits and rate tariffs to correct for an error in the rate-design spreadsheets for the R-3 Residential Heating customer class. Exh. KEDNE/ALS-8, at 1. This correction had the effect of decreasing the bill impacts stated in the initial filing for the typical residential heating customer from 20.5 percent in the peak season to 10 percent. Id. at 1.

America (AFL-CIO-CLC) (the "Union"). The Department also allowed Boston Edison Company, Cambridge Electric Light Company, Commonwealth Electric Company and NSTAR Gas Company (together, "NSTAR"), Fitchburg Gas and Electric Light Company ("FGE") and Western Massachusetts Electric Company ("WMECo") to intervene as limited participants.

On June 6, 2003, the Attorney General filed a Notice of Intent to File Testimony of two witnesses: Lee Smith of La Capra Associates on PBR and/or rate design issues and David J. Effron of the Berkshire Consulting Group on revenue requirement issues. Also on June 6, 2003, MASSCAP filed a Notice of Intent to File Testimony of Elliott Jacobson, Energy Director of Action, Inc. and chairman of the New England Community Action Association Energy Committee, on the burdens of low-income families and existing policies and programs that assist low-income customers.

On June 23, 2003, the Department conducted a follow-up procedural conference, and at that time, allowed The Energy Consortium and New England Gas Company to intervene as limited participants.

On June 26, 2003, the Department commenced 26 days of evidentiary hearings at its offices in Boston, Massachusetts, concluding on August 11, 2003. At the hearings, the Company presented the testimony of the following witnesses: Joseph F. Bodanza, Chief Financial Officer and Senior Vice President of Regulatory Affairs for KEDNE on the PBR Plan and other issues; Patrick J. McClellan, Director of Rate Recovery for the Service Company, on cost-of-service issues; Justin C. Orlando, Vice President of Human Resources for the Service Company, on employee salary, benefit and incentive compensation issues; Dr. Lawrence R. Kaufmann, Partner with Pacific Economics

Group, LLC, on the price-cap formula for the PBR Plan; Paul R. Moul, Managing Consultant for P. Moul & Associates, on cost of equity issues; Ann E. Leary, Manager of Rates for KEDNE, on post-test-year revenue adjustments and the allocated cost-of-service study; A. Leo Silvestrini, Director of Rates and Regulatory Affairs for KEDNE, on the proposed rate design and Weather Stabilization Clause; and Ronald B. Edelstein, of the Gas Technology Institute on gas industry research and development funding.

On July 7, 2003, the Attorney General submitted prefiled direct testimony of two witnesses, Lee Smith and David J. Effron. Also on July 7, 2003, MASSCAP submitted prefiled testimony of its witness, Elliott Jacobson.

On August 4, 2003, the Company submitted the rebuttal testimony of Mr. Moul, regarding Mr. Effron's testimony on the impact of the Company's proposed pension-reconciliation mechanism on the cost of equity; Mr. McClellan, regarding Mr. Effron's testimony on the Company's incremental cost adjustment and income-tax calculation; and Dr. Kaufmann regarding Ms. Smith's testimony on the Company's TFP and econometric research.

On August 11, 2003, the Attorney General filed the surrebuttal testimony of Timothy Newhard to address Mr. Moul's rebuttal testimony. The Attorney General was also granted the opportunity to submit oral surrebuttal testimony by Ms. Smith on the rebuttal testimony of Dr. Kaufmann.

The record in this proceeding consists of 1944 exhibits, including the Company's initial filing and responses to discovery and record requests. In accordance with the procedural schedule, initial briefs were filed by the Attorney General, DOER, MASSCAP, MDFA, MOC and Bay State on August 29, 2003. The Company's Initial

Brief is submitted in compliance with the Department's procedural schedule, as amended on September 9, 2003.[11]

III. COST OF SERVICE

A. The Company's Revenue-Requirement Analysis is Based on a Representative Test Year.

1. The Company's Use of 2002 as the Test Year Meets the Department Standard

In establishing rates for utilities subject to its jurisdiction, the Department relies on historical test-year data, adjusted only for known and measurable changes through the midpoint of the rate year (i.e., six months from the effective data of the Department-approved rate tariffs). Fitchburg Gas & Electric Light Company, D.T.E. 02-24/25, at 76 (2002); D.P.U. 88-67, at 77; D.P.U. 87-122, at 13; Eastern Edison Company, D.P.U. 1580, at 13-17 (1984). The use of a historical 12-month period of operating data as the basis for setting rates is intended to reflect a representative level of a utility's revenues and expenses that, adjusted for known and measurable changes, will serve as a proxy for future operating results. FG&E, D.T.E. 02-24/25, at 76; D.P.U. 88-67, at 77; D.P.U. 87-122, at 13; Eastern Edison, D.P.U. 1580, at 13-17 (1984). The selection of the test year is largely at the discretion of the utility. All that the Department requires is that the test year must represent a 12-month period (calendar or non-calendar), and that the test year does not overlap with the test year used in a previous case. Massachusetts Electric Company, D.P.U. 19257, at 12 (1977).

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[11] On September 5, 2003, the Company submitted a request to the Department for an additional day to file its Initial Brief, which enlarged the briefing schedule for the proceeding by one day. The Department granted the Company's request on September 9, 2003.

In this proceeding, the Company has submitted documentation in support of a revenue deficiency of $61,999,247, based on the test year ending December 31, 2002. Exh. KEDNE/PJM-2 [rev.2]. The test year meets the Department's standard because it is a recent 12-month (calendar) period that does not overlap with a test year used in a previous case.

2. The Department Must Reject the Attorney General's Arguments Regarding the SEC Audit and the Test Year.

The Attorney General claims that the results of the SEC audit of the Service Company show that the test year is unrepresentative (Attorney General at 19). The Attorney General contends that the Department should require the Company to:

(1) Adjust the cost of service to remove all of the corporate governance costs identified by the SEC;

(2) Reallocate all costs that fall in the categories identified by the sample transactions, and direct the Company to incorporate the reassignments in its accounting systems;

(3) Develop accounting procedures that incorporate Essex as a discrete entity in the development of the Service Company cost.

(id. at 25). The Attorney General's arguments in relation to the SEC audit are confused and misinformed. As a result, the Attorney General's recommendations to the Department are inappropriate and not supported by any basis in the record, and therefore must be rejected by the Department.

First, it is difficult to discern what exactly the Attorney General's argument is on this issue. For example, the Attorney General first argues that the Service Company costs are not representative and that, "because of the magnitude of these costs, the Department must reject the Company's request for rates based on them" (id. at 20). However, the Attorney General acknowledges that the Service Company is providing the majority of the Company's "customer and regulatory accountability functions, including billing, records, customer services, accounting, and finance activities (id. at 4).[12] There is no ratemaking standard or precedent that precludes the recovery of costs of providing service to customers because they are large in magnitude.

The Attorney General next argues that "it is not clear from the record that the Company has resolved all problems surrounding the transition process, especially problems associated with full compliance with SEC financial disclosure requirements and the allocation of Service Company costs" (id. at 21). At the Attorney General's request, the Company requested and obtained an official letter from the SEC ending its examination and terminating the audit. RR-AG-78 [supp.]. There is no more clarity that can be added to the subject, unless the Attorney General is implying that issues raised by the SEC in the course of its audit were not resolved and that the SEC has failed to require resolution of those issues prior to the termination of its audit. However, this conclusion is not only unreasonable, it is contradicted by evidence in the record showing that each and every issue raised by the SEC has been addressed by KeySpan to the satisfaction of the SEC. RR-AG-79.

The Attorney General next claims that the test year is not representative because of: (1) the lack of historical performance data demonstrating the successful integration of services provided by the Service Company; (2) the complexities and irregularities of the

[12] The Attorney General notes that the majority of Service Company costs are booked to administrative and general ("A&G") accounts, "rather than to the accounts prescribed by the Department in its Uniform System of Accounts" (Attorney General at 20, fn.12). This is simply inaccurate because the charges are incurred at the Service Company level and charged (with burdens) to the Company, rather than being costs that the Company incurs directly. Notably, the Attorney General's witness, Mr. Effron, acknowledged that booking amounts paid to the Service Company to the accounts selected by the Company would be consistent with the Department's System of Accounts. The creation of the Service Company results in the Company incurring certain A&G expenses in an indirect manner as opposed to directly. This change appropriately results in certain expenses being booked to A&G accounts that are different from those accounts to which they were booked previously.

Company's cost accounting; (3) and the newness of the Company's information systems such as the Customer-Related Information System ("CRIS") and the Oracle system (id.). What is not clear to the Company is why a year in which there is (1) full integration of the Service Company, and (2) the completion of a comprehensive audit by the SEC of all of the Service Company's costs and cost-allocation methodologies (to an extent that could never be duplicated in a rate proceeding by the Department), would not make 2002 an ideal test year in determining the representative level of costs for Boston Gas customers. In fact, the Attorney General's arguments are entirely without merit – 2002 is not the first year that the Company has operated under a Service Company structure, just the first year of full integration. Exh. KEDNE/JFB-1, at 18. The accounting and cost allocation will always be complex; changing the test year will not change that fact. There are no "irregularities" in accounting practices, although errors and corrections will occur because they are an unavoidable and expected circumstance of the business environment. The Oracle system has been in use by the Company since January 1999 and the CRIS system, although newly implemented for New England customers, has been in use by KeySpan for many years.

Most importantly, the Attorney General points to no evidence in the record linking these factors to an unrepresentative level of costs, or otherwise showing that the Service Company costs allocated to Boston Gas are not representative of the level of costs that Boston Gas will incur in the future.[13] None of these circumstances, even if true

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[13] In fact, the Company made all of the adjustments to the test-year cost of service that resulted from the SEC audit. These adjustments have reduced the cost of service and ensure that the costs included in the test year are representative of the costs allocated to the Company in the future. Exh. KEDNE/PJM-12; Exh. KEDNE/PJM-12. In the context of the scope of the SEC audit, the totality of the accounting changes found by the SEC to be appropriate are de minimis.

and even if significant, warrant the rejection of the test year, nor do they serve as any legal or policy basis for rejecting Service Company costs.

Also contrary to the Attorney General's assertions, the Company's witnesses have not in any way "resisted attempts to determine whether the Company has proposed representative costs (see Attorney General at 22). In fact, the Company and the Company's witnesses have gone to great lengths to elucidate the Service Company charges. See e.g., Exh. AG-1-8; AG-1-28, AG-17-21, AG-17-22, AG-17-23; AG-17-24; AG-17-25; AG-17-28, AG-17-29; AG-31-6. Yet, despite having all of this information, the Attorney General cites to no evidence that the allocated costs are not representative or that such costs do not represent a fair and equitable allocation of costs to Boston Gas.[14] Accordingly, the Company's evidence on the record regarding the allocation of costs is uncontradicted.

With respect to the specific issues relating to the SEC audit that are raised by the Attorney General, the Company's response is as follows:

1. The $93 million identified by the SEC in Exh. AG-17-33 [supp.], Finding 19, is the total amount of corporate governance costs (by category) incurred by the Service Company in 2002. Within these categories, costs are allocated by project activity. Therefore, of the $93 million, the SEC required only $47.1 million to be reallocated because the bulk of the $93 million in corporate governance costs were allocated using factors other than the three-point formula allocators (mainly GO1). RR-AG-75. The SEC's Examination Staff (the "Staff") noted in Finding 2 that KeySpan's three-point formula (in the GO1 allocator) excluded the holding company from all three factors. The Staff suggested that the factor be revised to include the parent company's stand-alone assets and revenues including inter-company dividends. Accordingly KeySpan revised its three-point formula and reallocated 2001, 2002 and 2003 project/activities affected by this revision. The SEC has accepted KeySpan's reallocation and the

[14] Record evidence demonstrates that, if O&M costs are analyzed in the period 1998 through 2000 and compared to 2002, with the exclusion of pension costs, sales and marketing expense and system-reliability O&M expense, O&M costs have increased by only 4 percent in comparison to the average of the 1998-2000 time period, without consideration of inflation.

effect of this reallocation has reduced the Boston Gas cost of service by $401,294.

2. The Service Company provides only a minimum amount of services to the unregulated affiliates because those affiliates have their own corporate and administrative staff. Unregulated affiliates do not share in general corporate services the way that regulated companies are allowed for competitive reasons. For example, the payroll department of the Service Company performs payroll activities for all regulated utilities served by the Service Company, but does not perform those services for unregulated subsidiaries.

3. The Financial Planning costs were not part of the reallocation and were accepted as is. There is no evidence that Merger/Acq Res Plan costs fall within the SEC's definition of costs that should be allocated to the holding company.

4. All costs associated with the Shareholder Meetings and Board of Directors expenses have been removed from the Boston Gas cost of service. Exh. KEDNE/PJM-12. Therefore, it is irrelevant whether the SEC accepted particular invoices to evaluate the costs associated with those activities.

5. The Staff requested and reviewed all documentation supporting the derivation of allocation factors for 2001, 2002 and 2003. See, Exh. 17-29. This documentation identifies the statistics comprising the data points of each allocation formula and clearly identifies that Essex Gas is combined with Boston Gas for the purposes of allocations. The Staff noted no exceptions with KeySpan's allocation formulas other than the exclusion of the holding company from its three-point formula.

Accordingly, each of the Attorney General's arguments regarding the Service Company costs and the use of 2002 as the test year are without merit and without support in the record, and therefore, must be rejected by the Department. In addition:

(1) There is no basis in law or fact for the Department to adjust the cost of service to remove all of the corporate governance costs charged to Boston Gas by the Service Company. The Company has already removed the costs that were identified by the SEC as not properly charged to Boston Gas and there is no evidence that any of the remaining cost allocations are inappropriate for inclusion in Boston Gas rates;

(2) There is no basis to reallocate all costs that fall in the categories identified by the sample transactions or to incorporate the reassignments in the

Company's accounting systems, because the Company has already removed all of these costs from the cost of service.

(3) The Company has already calculated and provided the cost allocations that would apply to Essex as a discrete entity within the Service Company. RR-AG-2. Using the Oracle system, the Company is able to produce these calculations at any time, and no further processes are required.

B. RATE BASE

1. The Company's System Investments Since 1995 Meet the Department Standard For Inclusion in Rate Base

For plant costs to be included in rate base, the expenditures must be prudently incurred, and the resulting plant must be used and useful in providing service to customers. FG&E, D.T.E. 02-24/25, at 22; citing Fitchburg Gas and Electric Company, D.T.E. 98-51, at 9; D.P.U. 96-50, at 15; Boston Gas Company, D.P.U. 93-60, at 42 (1993); Commonwealth Gas Company, D.P.U. 85-270, at 60-107. The Department considers plant to be "used and useful" if the plant is in service and provides benefits to customers. D.T.E. 02-24/25, at 22; D.T.E. 98-51, at 9; D.P.U. 96-50, at 15. For ratemaking purposes, the Department determines rate base according to the cost of the utility's plant in service as of the end of the test year. D.P.U. 96-50, at 15.

For revenue-producing investments, the Department requires the Company to: (1) use cost-benefit analysis or a similar management tool for all construction projects in excess of $100,000; (2) include all indirect costs as part of its budget authorizations; and (3) support the project authorizations with sufficiently detailed cost-benefit analyses commensurate with the project's complexity and expense. D.P.U. 96-50, at 17-18; D.P.U. 93-60, at 35-36. With respect to the rate of return on revenue-producing projects, the Department has endorsed an analysis of the two basic impacts on existing customers when new customers are connected to the system: (1) the change in gas costs recoverable through the Cost of Gas Adjustment Clause; and (2) the rate of return realized on the incremental rate base required to serve new customers on the system. D.P.U. 96-50, at 22. The Department has stated that customers receive benefits when, all other things being equal, the rate of return on the incremental rate base exceeds the utility's overall required cost of capital. The Department further allows a gas company to include anticipated growth in its estimate of the benefits to be realized on the incremental rate base required to serve the new customers. Id.; Colonial Gas Company, D.P.U. 84-94, at 6 (1984). To meet this standard, the Department has accepted: (1) capital authorization and closed work order reports; and (2) a cost-benefit analyses in the form of an internal rate of return ("IRR") on an aggregate basis for growth-related investments in the distribution system. D.P.U. 96-50, at 18.

In this case, the Company has provided the Department with: (1) capital authorization and closed work order reports for all revenue producing investments over $100,000 made in the years 1996 through 2002 (Exh. AG-1-19); and (2) cost-benefit analyses in the form of a fully loaded and marginal internal rate of return ("IRR") calculations on all revenue-producing investments over $100,000, and on an aggregate basis for all growth projects, which includes the direct and indirect costs of the Company's growth construction, as well as the costs of the Company's promotional programs. KEDNE/PJM-9 and PJM-10; Exh. DTE-4-27; DTE-4-28; MOC-2-10. The cost-benefit analysis shows that the internal rate of return on the Company's growth–related investments in 2002 was 18.8 percent, which is more than double the Company's weighted cost of capital as determined in D.P.U. 96-50 of 9.38 percent. This analysis demonstrates that the Company's existing customers have received substantiated benefits as a result of the Company's growth-related investments.

For non-revenue producing investments, such as street main replacements, the Department requires the Company to demonstrate that it sought to contain the overall cost of such projects. D.P.U. 96-50, at 17. To meet this standard, the Department has accepted a description of the Company's ongoing efforts to control and contain construction costs. Id. at 19. In this case, the Company has provided the Department with (1) capital authorization and closed work order reports for all non-revenue producing investments over $100,000 made in the years 1996 through 2002 (Exh. AG-1-19; and (2) a description of the Company's cost-containment efforts. Exh. KEDNE/PJM-1, at 49-51. The Company's most significant cost containment efforts include: (1) enhanced bypass analysis; (2) participation in a purchasing consortium; (2) upgrades to the Automated Mains and Mapping System ("AMMS") to allow for increased coordination of growth and system reinforcement construction schedules; (3) warehouse consolidation; and (4) changes to the contractor bidding process. Id.

Accordingly, the Company has included in the cost of service total rate base of $627,449,530 as of December 31, 2002. See, Exh. KEDNE/PJM-2 [rev.2], at 38. The Company derived this amount by starting with utility plant of $2,003,202,253, and removing the merger-related acquisition premium and other items[15] totaling $813,987,223, for total utility plant of $1,189,215,030. Id. To this amount, the Company

15 In addition to the goodwill adjustment, the Company reduced rate base for the following items: (1) to remove net leasehold improvements associated with One Beacon Street of $136,291; (2) to remove the net book value of the Concord Property sold since 1996 of $132,859; (3) to remove the portion of the CRIS system investment relating to the Essex customer operations ($1,705,080) ; and (5) to add software investments that are non-incremental to the Boston Gas operations and were allocated to Colonial under the SEC allocations of $937,026. Exh. KEDNE/PJM-2, at 39.

added Other Materials and Supplies of $4,753,952, which is the balance of Other Materials and Supplies as of December 31, 2002, less the difference between the year-ending number and the 13-month average of $3,909,146, or $844,806. To these amounts, the Company added Working Capital of $16,676,353, for total utility plant of $1,209,800,529.[16]

Deductions to rate base including accumulated depreciation totaled $605,067,291 from the Company's books as of December 31, 2002. The Company adjusted the balance of rate-base deductions as of December 31, 2002 by $22,716,292 to account for two items: (1) to remove the amortization of intangible plant of $22,665,437 associated with the acquisition premium of $22,716,292; and (2) to remove refundable customer construction advances of $50,855. Accordingly, the total utility plant of $1,209,800,529, was reduced by $582,350,999, to arrive at Total Rate Base of $627,449,530.

2. The Department Must Reject the Attorney General's Arguments Regarding the Company's Rate Base Calculations

The Attorney General contends that the Department should adjust the Company's rate base calculation the following ways: (1) to exclude rate-base investment for growth-related plant additions (Attorney General at 25-27); (2) to exclude from rate base the costs of a non-revenue producing project in West Roxbury (Work Order #79111) (id. at 27-28); (3) to exclude the rate-base expenditures associated with the CRIS computer system (id. at 29-33); (4) to reduce the amortization for intangible plant by $266,000; and (5) to deduct from rate-base the test year-end balance of customers' construction advances (id. at 33-34). As with his other arguments in his initial brief, the Attorney

[16] This amount is based on the calculation provided in Exh. KEDNE/PJM-2 [rev.2], which incorporates a correction in the working capital calculation. RR-DTE-117.

General's rate-base recommendations are without record support and disregard the Department's standards for recovery of rate-base expenditures in rates. Therefore, the Attorney General's recommendations must be rejected by the Department.

(i) The Company Has Met the Department's Standard for Inclusion of Revenue-Producing Investments in Rate Base.

The Attorney General argues that the Department should exclude from rate base 16 revenue-producing projects totaling $5,941,056, where the IRR upon completion of the project was less than the Company's 9.38 percent cost of capital set in D.P.U. 96-50 (Attorney General at 26-27, fn.20). This would reduce the total cost of service by $568,000 (id.). Although the Attorney General does not request further exclusions, the Attorney General implies that the Department should exclude from rate base 10 additional revenue-producing projects that had an IRR upon project completion that fell below the Company's annually established internal threshold for the use of capital funds (id. at 26-27) (11.75 percent for residential customers and 12.75 percent for commercial and industrial). In combination with the first 16 projects, this would require the exclusion of $13,366,144 in rate-base investment and a reduction to the cost of service of $1,351, 990 (id. at 26-27, fn.21). Both of these adjustments are inconsistent with Department precedent given the evidence presented on the record.

In determining whether rate-base additions are prudent and eligible for recovery through rates, the Department has stated that it evaluates whether the utility's actions, based on all that the utility knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed. See e.g., D.P.U. 93-60, at 24. The Department has further stated that determinations as to the prudence of a utility's actions may not properly be made on the basis of hindsight judgements, nor is it appropriate for the Department to merely substitute its best judgment for the judgments made by management of the utility. Id., citing, Attorney General v. Department of Public Utilities, 390 Mass. 208, 229 (1983). Accordingly, the Department has allowed the Company to include in rate base revenue-producing projects with a negative IRR or an IRR upon project completion that falls below the Company's weighted cost of capital as established in its last base-rate proceeding. See, e.g., Colonial Gas Company, D.P.U. 84-94, at 4-6 (1984); D.P.U. 96-50, at 23-24. To obtain rate recovery, however, the Company must demonstrate that the actual costs of construction were greater than anticipated due to circumstances not foreseen at the time the project costs were estimated at the outset of the project. Id.

In this case, the Company has provided documentation regarding the reasons for post-estimation cost increases for each of the 26 projects referenced by the Attorney General. RR-AG-59. In each case, the IRR calculated based on estimated costs exceeded the Company's weighted cost of capital of 9.38 percent, and in each case costs were incurred during the construction phase that could not have been foreseen by management at the outset of the project. The Attorney General does not contest the cost estimations, the calculations of the IRRs based on those estimations, or that cost increases were encountered during the construction phase that could not have been foreseen in the estimation process (i.e., changes required by state or local municipalities, ledge encountered during construction and other unforeseeable circumstances). RR-AG-59 The Attorney General's only argument is simply that the IRRs fell below the weighted cost of capital of 9.38 percent upon completion of the project. This is insufficient to support a finding by the Department that the projects "were, from the start, uneconomic, imprudent investments" that should be excluded from rate base, as claimed by the Attorney General (Attorney General at 26-27).[17] To the contrary, the record shows that, at the time the investments were undertaken, the projects would provide a return to the Company in excess of the cost of capital, and therefore, the Company's decision to commence the projects was reasonable in light of the circumstances that then existed. Accordingly, these projects should not be excluded from rate base.

(ii) The Company Has Met the Department's Standard for Inclusion of Non-Revenue Producing Investments in Rate Base.

The Attorney General contends that the Department should remove from rate base the costs associated with the West Roxbury project, set forth in Work Order #79111 because the Company has not shown how it attempted to control its costs (Attorney General at 28). In relation to this project, the Attorney General notes that the street main authorization shows that the project was intended to add 800 feet of 12-inch main to serve the West Roxbury High School at a projected expense of $87,000, including overhead (id., citing, AG-12)). At completion, the project cost $575,541, according to the closing report (Exh. KEDNE/PJM-8, at 1). The Attorney General's stated basis for the exclusion is that the Company failed to provide the level of detail necessary for the Department to evaluate whether the West Roxbury project costs were "fully monitored and controlled" (Attorney General at 28). This claim should be rejected for several reasons.

[17] Ten of the projects highlighted by the Attorney General do not even fall below the weighted cost of capital, but rather resulted in a return that falls below the Company's internal threshold for use of internal capital. These investments produce a net benefit for customers, who are charged rates based on the weighted cost of capital.

The record shows that, when the job was originally estimated, it was projected that 800 feet of pipe would be installed. Exh. AG-1-19, Street Main Authorization. for Work Order #79111 (page 1). However, when the job was completed, the over 1650 feet were installed (page 4), which means that the work order involves a much larger job than originally estimated and would have likely involved two adjacent projects that were more efficiently accomplished at the same time. Second, the Department's precedent does not require the Company to perform cost-containment analyses on a project by project basis. Because a cost-benefit analysis is not appropriate or applicable to a non-revenue producing capital addition, the Department's precedent requires the Company to make a demonstration of its cost containment efforts in regard to its overall construction activities, which the Company has done in this case. See, Exh. KEDNE/PJM-1, at 49-51. Although the Company always has the burden of responding to questions on the record regarding specific projects, the Department has never required the Company to produce cost-containment descriptions for each individual project undertaken between rate cases. Nor should such a requirement be established because it represents a level of detail that would be extraordinarily burdensome to the Company's day-to-day management process. For example, in D.P.U. 96-50, the Company discussed the operation of the AMMS system and bidding processes, which were designed to reduce costs across the board for the Company's construction activities. D.P.U. 96-50, at 19-20, 24. Accordingly, there is no basis to exclude from rate base the cost of the West Roxbury project.

(iii) The Company Has Met the Department's Standard for Inclusion of CRIS-Related Investments in Rate Base.

The Attorney General contends that the Department should exclude the Company's $23.6 million allocation of the CRIS investment from rate base because the

Company has not demonstrated that the investment in the CRIS system was a prudent expenditure (Attorney General at 32). The Attorney General's basis for a finding of imprudence are the claims that: (1) the Company has not provided a cost-benefit analysis or documented its cost containment efforts; (2) the Company did not comply with the Department's so-called "outside services procurement requirement;" and (3) the Company experienced "significant problems with the conversion and implementation of the new billing system" (id. at 30-31). As is the case with the revenue and non-revenue producing projects discussed above, the Attorney General offers no analysis of the facts that are on the record regarding the CRIS investment. The Attorney General has simply offered broad recommendations to reject a substantial investment that the Company has made on behalf of customers. As a result, none of the Attorney General's claims provide a sufficient basis for a finding of imprudence.

As noted above, the Department has stated that, to determine whether rate-base additions are prudent and eligible for recovery through rates, it will evaluate whether the utility's actions, based on all that the utility knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed. See e.g., D.P.U. 93-60, at 24. Determinations as to the prudence of a utility's actions are not properly made on the basis of hindsight judgements, nor is it appropriate for the Department to merely substitute its best judgment for the judgments made by management of the utility. Id., citing, Attorney General v. Department of Public Utilities, 390 Mass. 208, 229 (1983). Accordingly, a prudence review must be based on findings on how a reasonable company would have responded to the particular circumstances and whether the company's actions were in fact prudent in light of all circumstances that were known or reasonably should have been known at the time a decision was made. Western Massachusetts Electric Company, D.P.U. 85-270, at 23-24 (1986); Boston Edison Company, D.P.U. 906, at 165 (1982). The Company has met the Department's standard in this case in relation to the CRIS investment.

First, with respect to a cost-benefit analysis or cost-containment analysis, the Company provided a detailed explanation as to its decision-making process in its initial filing.[18] Exh. KEDNE/PJM-1, at 46-48. In that regard, the record shows that the customer-information system in use by Boston Gas prior to the merger ("CSS") was near the end of its useful life and was founded on a database structure that had become obsolete and lacked the functionality needed to provide the desired level of customer service. Exh. KEDNE/PJM-1, at 47; Exh. AG-6-87. The record also shows that the CRIS system offered a more sophisticated database structure, real-time and event driven processing and greater flexibility and efficiency in retrieving and managing customer data and allowing for interface between related system components. Exh. KDENE/PJM, at 48. Lastly, the record shows that the analysis employed by the Company was an assessment of the costs of developing and maintaining a new system for Boston Gas (and the other New England companies) versus the cost of converting the CSS system to the CRIS system. Exh. AG-22-9; AG-6-87. In that regard, the Company's analysis showed that the cost of developing a new system would be substantially more than the cost of converting to the CRIS system. Id.

18 In discussing the cost-benefit analysis associated with the CRIS system, the Attorney General cites to Tr. 7, at 805-806, as evidence that the Company has not performed an analysis. However, at this point in the transcript, the Company's witness is more generally discussing non-revenue producing projects, and is not specifically referring to the CRIS system. In the Company's response to Information Request AG-22-9, the Company stated that it had, in fact, performed a study of the costs that would be incurred to develop a new system versus the cost of converting to the CRIS system.

In addition, with respect to cost-containment efforts associated with the project, the record shows first that management chose to convert the CRIS system rather than purchase a new system because the cost of a new system would have been significantly greater than the investment in CRIS. Exh. AG-22-9. The original CRIS system was developed by KeySpan for use in serving its New York customers at a significant cost, none of which is allocated to Boston Gas rates. Moreover, the cost of migrating the outdated CSS system to the CRIS system involved: (1) modifications to KeySpan's existing system to accommodate Massachusetts terms and conditions of service, and (2) data conversion, both of which could be most efficiently achieved using internal resources, supplemented by outside contractors. Id. The record further shows that the Company solicited bids from approximately 50 vendors to act as technical consultants to internal personnel in completing the conversion Id., see, also, Exh. AG-6-87 [supp.]. Contrary to the Attorney General's assertions, the record shows that KeySpan put in place processes to evaluate bids and to qualify individual contractors, and allowed for a 30-day evaluation period to replace contractors that did not perform according to expectations. Exh. AG-6-87.

Accordingly, although cost-benefit analyses are not generally applicable to non-discretionary, non-revenue producing capital projects, the record shows that the Company has utilized a "similar management tool" to evaluate the business circumstances and alternatives associated with the need to upgrade or replace the CSS system, as required by Department precedent. D.P.U. 96-50, at 17. In addition, the record shows that management determined that the cost of migrating to the CRIS system was substantially less than developing a new system and that the conversion would utilize a greater level of internal resources, reducing the overall cost of the project. Accordingly, the record shows that the Company did employ a management tool to assess the costs of the system, and once deciding to convert rather than purchase a system, took steps to control and minimize cost. As a result, there is no basis on the record for a finding that the Company acted imprudently in making the CRIS investment and the Attorney General's claim that the CRIS investment should be disallowed due to a lack of cost-benefit analysis or cost-containment measures should be rejected.

Moreover, with the exception of the "extraordinary" bonus payments totaling $63,407, the Attorney General has raised no issue with the actual costs that were incurred for the project. RR-AG-100. The Attorney General's claims are mainly that the Company did not "comply with the [Department's] outside services procurement requirement" (Attorney General at 30). As stated above, the CRIS system investment involves a system conversion accomplished by internal resources supplemented by outside consultants (that were procured by a competitive solicitation process) and did not involve a system purchase or outsourcing to a single vendor. The only aspect of the project that was not competitively bid was the limited technical assistance required for the data-conversion tasks and this aspect was not bid out because the Company believed a unique expertise was required. Exh. AG-6-87. For this purpose, the Company ultimately retained the services of an individual (in the employ of the consulting firm "Technology Consulting Associates"), who had overall responsibility for a previous system conversion involving CRIS that was undertaken by KeySpan prior to its acquisition of Eastern Enterprises. Id. This individual was uniquely situated to accomplish the data conversion, and no bid process would have produced a similar result at a lesser cost. Id.

Lastly, there is no evidence in the record to support the claim that "the Company experienced significant problems with the conversion and implementation of the new billing system" (Attorney General at 30). This statement is simply untrue. As support for this statement, the Attorney General refers to "late payment charges not being billed, misleading reports of ECS data, missing write-off recovery information . . . and faulty weather normalization data" (Attorney General at 30-31). Both the CSS and CRIS systems are complicated data systems designed to handle data in specific ways and to generate reports for specific purposes that have evolved over time. It is to be expected that minor implementation issues will arise in terms of disparities between the data handled or reports generated by one system that differ from the other system. All of the instances listed by the Attorney General constitute nothing more than normal and routine implementation issues relating to the generation of certain regulatory reports that differ between the New York and New England jurisdictions (such as late payment charges and bad-debt writeoffs). Moreover, the record shows that these issues have already been corrected or resolved.[19] See, e.g., RR-AG-36.

Even if the implementation issues had been significant, which they were not, the Department has stated that a prudence review is based on a review of information known to management at the time a decision is made, and that a determination as to the prudency of a utility's actions is not properly made on the basis of hindsight judgments. Therefore, the fact that conversion issues are encountered, whether significant or insubstantial is

[19] For example, in the case of the alleged "faulty weather normalization data," the data produced by CRIS was accurate and complete. However, the difference between the New England and New York process for compiling weather normalization data was not immediately recognized in preparing rate-case documentation.

irrelevant, unless they stem from a factor that should have been known to management at the outset.

(iv) The Attorney General's Recommendations on Amortization of Intangible Plant are Inconsistent with Department Precedent.

The Attorney General recommends that the Department (1) reduce the Company's unamortized non-informational software balance by $266,000 to an annual level of $155,000 based on the formula set forth in D.P.U. 96-50, at 100-101;[20] or (2) abandon the formula in D.P.U. 96-50 and allow the Company to recover its remaining unamortized intangible plant balance over the term of the PBR Plan.

The Attorney General's claim should be rejected because the Attorney General is misapplying the Department's findings in D.P.U. 96-50. In D.P.U. 96-50, the issue was that the cost item subject to amortization (i.e., the Salem LNG tank repairs) was deemed by the Department to be non-recurring. D.P.U. 96-50, at 100 (stating "[w]e find the Company's argument concerning recurring amortizations to be unpersuasive"). The Company was recovering the cost of the Salem LNG tank repairs only because it had previously found the expense to be in the nature of an extraordinary expense item warranting amortization. See, D.P.U. 1100, at 91. In this case, the Attorney General is making the mistake of attempting to extend this principle to the amortization of intangible plant, which is not an extraordinary expense item. These expenses are associated with normal capital projects representing nine separate amortizations. Specifically, the Company's capitalized software projects are recurring in nature. The

[20] The Attorney General states that the Company has not reduced the balance of $421,000 for non-information software at the end of the test year for the amortization that will occur by the date of the Department's order ($319,722 x 10/12), or $266,000 (Attorney General at 33).

record shows that the Company has capitalized software additions every year (e.g., 12 in 2002, 8 in 2001). Exh. KEDNE/PJM-2 [supp.], at 164-167. In 2003 and going forward, a variety of software projects will be capitalized and the amortizations of those projects will replace the amortizations of the nine projects that are scheduled to be fully amortized before the end of the PBR period. Accordingly, the Attorney General's recommendation to reduce the Company's unamortized non-informational software balance by $266,000 to annual level of $155,000 is unfounded, and must be rejected by the Department.

(v) The Company Has Met the Department's Standard for Exclusion of Customer Construction Advances from Rate Base

The Attorney General argues that Customer Construction Advances should not be treated differently from any other "zero cost" funds provided by customers, and therefore, the Department should deduct the test-year end balance of Customer Construction Advances from the Company's rate base in determining rates (Attorney General at 34). The Company in 2002 for the first time received customer advances that were refundable if the customers met certain growth goals. Therefore, these amounts are properly included.

3. The Company Has Met Its Burden For Inclusion of Investments in Rate Base

As discussed above, the Attorney General is recommending that the Department make the following adjustments to the rate base calculated by the Company: (1) to exclude expenditures for growth-related plant additions, totaling $5,941,056; (2) to exclude the costs of a non-revenue producing project in West Roxbury (Work Order #79111), totaling $575,541; (3) to exclude investment associated with the CRIS computer system, totaling $23.8 million; (4) to reduce the amortization for intangible plant by

$266,000; and (5) to deduct from rate-base the test year-end balance of customers' construction advances, totaling $50,855. As demonstrated above, the Attorney General has provided an insufficient basis for the Department to find on his behalf on any of these arguments.

C. REVENUE ADJUSTMENTS

1. The Company Has Proposed Revenue Adjustments That Are Consistent with Department Precedent.

In order to establish representative revenue levels for the determination of the revenue deficiency and the establishment of base rates, the Company proposed a number of adjustments to test-year revenues. These post-test year revenue adjustments and the record evidence supporting the Company's adjustments are briefly summarized below.

➢ Weather Normalization Adjustment

The Company's weather adjustment is designed to normalize revenues and billing determinants to account for warmer- or colder-than-normal weather experienced during the test year (Exh. KEDNE/AEL-1, at 3). Consistent with the method used by the Company in its previous rate case, D.P.U. 96-50, the Company conducted an analysis on a customer-by-customer basis for all classes, except G-44 and G-54 (id. at 4).[21] The Company's weather-normalization adjustment increases test-year revenues by $5,520,760.

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[21] Pursuant to the Department's request, the Company performed weather-normalization adjustments based on a rate-class basis, rather than the customer-by customer basis used by the Company in this filing (Exh. DTE-3-6). As demonstrated by that analysis, the rate-class method yields a weather normalization adjustment of $5,448,749, as compared to the Company's adjustment of $5,520,760 (Exh. DTE-3-6; Tr. 7, at 728). This discrepancy is de minimis (as compared to total base revenues of $267 million) (Tr. 7, at 729). In addition, the Company's customer-by-customer method is more detailed and precise than the aggregated rate-class method (Tr. 7 at 728-729). Accordingly, the Company requests that the Department approve the weather-normalization methodology set forth in the initial filing.

Specifically, the Company weather-normalized each bill issued during each month of the test year for customers in all weather-sensitive classes (id.). Actual billing usage was divided into base load and heating use for each customer (id.). Base load was obtained from the Company's billing system and is calculated annually for each customer based on summer consumption (id.). Actual heating use is calculated as the difference between billed use and base load (id.). Normal heating use was derived by multiplying actual heating use by the ratio or normal degree days to actual degree days for the associated billing period for each customer (id.). Normal volumes are the sum of the base load and normal heating use (id.). Also consistent with Department precedent, the Company calculated normal degree days by averaging the degree days over the 20 year period from January 1983 through December 2002 (id.).[22] D.T.E. 02-24/25, Commonwealth Gas Company, D.P.U. 87-122 (1987); Berkshire Gas Company, D.P.U. 92-210, at 28.

In addition, because the Company's rate schedules reflect two "usage blocks," i.e., the headblock and the tailblock, each with different rates, once the total throughput was weather normalized, the Company distributed the normal usage to the appropriate headblock and tailblock for each rate class (Exh. KEDNE/AEL-1, at 4**;** Tr. 7, at 742-743). The Company then calculated the weather normalization throughput adjustment by subtracting the actual headblock and tailblock throughput from the normalized headblock

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22 The Company revised several exhibits initially presented to the Department that inadvertently miscalculated the Company's monthly actual and normal degree days (Tr. 7, at 750-756; see also RR-DTE-19 (revised)); Exh. DTE-2-40 (revised); Exh. DTE-3-6 (revised); Exh. AG-8-30 (revised); Exh. DTE-10-18 (revised). The revisions are associated with the Company's conversion to the CRIS billing system, which calculates daily degree days by averaging the temperature over 9 intervals and subtracting this average from 65 (RR-DTE-19 (revised)). In addition, a "day" is defined by the CRIS billing system as a "gas day" which is a 24-hour period beginning at 10:00AM (id.).

and tailblock throughput for each rate class for each month (Exh. KEDNE/AEL-1, at 4-5). In order to calculate the weather-normalized base rate increase, the Company multiplied the appropriate headblock and tailblock volumetric rate for each rate class by the corresponding normalized throughput adjustment (id. at 5). Accordingly, the weather adjustment is the difference between the actual and normal base revenue for all schedules, except G-44 and G-54 (id.).

With regard to the G-44 and G-54 rate classes, the Company calculated the weather normalized therms in the exact same manner as it calculated the weather normalized therms for all other rate classes (Exh. AG-8-32). Customers taking service under these rates are billed on a demand basis, based on the customer's Maximum Daily Contract Quantity ("MDCQ") in a relevant historical period, rather than a volumetric basis (Exh. KEDNE/AEL-1, at 5; Exh. DTE-2-46). Specifically, each peak and off-peak season, the Company calculates the MDCQ for each customer using the customer's actual throughput from the prior peak or off-peak season (Exh. KEDNE/AEL-1, at 5). Customers are then billed a demand rate based on the calculation of the MDCQ in the prior period (id.).

In order to derive the weather impact on these two rate classes, the Company weather-normalized the aggregate MDCQ for each class, rather than the historical volumetric throughput (id. at 6). To do this, the Company calculated the average daily use for each customer class by dividing the normal monthly volumes by the average number of billing days in each month (id.). The Company then multiplied the highest average daily use in the peak and off-peak periods by 30 to derive the average-month basis and then divided by 21 to place the result on an MDCQ basis (id.; see also Exh.

DTE-2-47). This calculation was repeated by substituting actual monthly volumes for the normal monthly volumes to derive a calculated actual MDCQ (Exh. KEDNE/AEL-1, at 6). The ratio of normalized MDCQ to calculated actual MDCQ was than multiplied by the actual billed MDCQ to calculate the normal billed MDCQ (id.). The difference between the normal-billed MDCQ and the actual-billed MDCQ was than multiplied by the effective MDCQ rate (id.). This resulted in the G-44 and G-54 weather normalization revenue adjustment (id.; Exhibit AEL-2, at 4, 5; Exh. DTE-2-46).

Pursuant to this methodology, the Company's proposed a revenue adjustment related to weather normalization of $5,520,760 (id. at 3; Exh. KEDNE/AEL-2, at 3). Accordingly, the Company's weather normalization adjustment constitutes a known and measurable adjustment to the Company's test-year revenues and should be approved by the Department.

➢ Billing Day Adjustment

The Company performed a billing day adjustment to account for the revenue impact of the difference between the actual number of billing days (365.45) in the test year and the number of billing days (365.25) in a normal year (Exh. KEDNE/AEL-1, at 6; Exh. KEDNE/AEL-2, at 6; Exh. AG-8-35; Exh. DTE-1-28). The Company calculated the billing day adjustment in the same manner as approved by the Department in D.P.U. 96-50 (Phase I) (Exh. AG-8-35, Exh. AG-8-36).[23] The Company's billing-day adjustment reduced test-year revenues by $164,726.

The billing day adjustment was determined by first determining the difference between the test-year billing days and normal billing days (Exh. KEDNE/AEL-1, at 6).

[23] See D.P.U. 96-50 (Phase I) at 40.

The calculation was adjusted by: (1) the portion associated with heating load; and (2) the portion associated with base load (id. at 6-7). The heating portion was calculated by averaging January and December billing degree days per day, and multiplying the result by the average December and January heating increment to determine average daily heating use (id.; Exh. AG-8-35). The average daily heating use was then multiplied by the difference in billing days to calculate the heating portion of the billing day adjustment (Exh. KEDNE/AEL-1, at 6). The heating increment was determined by subtracting August base load from actual January and December billing usage to obtain heating usage (id.). The heating usage was divided by actual billing degree days for each month and the result was then averaged (id.).

The baseload portion was determined by multiplying the billing day difference by the August base use per day (id.). The resulting volume was added to the heating adjustment (id.). This total was then multiplied by an average of January and December revenue rates to obtain the billing day revenue adjustment (id.). The Company's Billing Day Adjustment reduced test-year revenues by $164,726 (id.; Exh. KEDNE/AEL-2). Accordingly, the Company's billing day adjustment constitutes a known and measurable adjustment to the Company's test-year revenues and should be approved by the Department.

➢ Customer Charges Adjustment

The Company reduced test-year revenues by $543,219 to account for the change in the calculation of customer bills resulting from the conversion to the Customer Related Information System ("CRIS") in July 2002 (Exh. KEDNE/AEL-1, at 7; Exh. KEDNE/AEL-2, at 7; Exh. DTE-1-29). The bill-calculation routine in CRIS calculates all monthly customer bills on a per-day basis depending on the number of days in a customer's billing cycle (id., at 8). This change in the bill calculation routine affects the amount of revenue the Company bills through the customer-charge portion of the rates (id.).

The Company calculated the impact of this change on the revenues billed during the first six months of the test year by comparing the customer charges actually billed to what would have been billed if the CRIS system were in place effective July 1 (id.). To do this, the Company recalculated revenues using the customer charges that became effective with the conversion to CRIS and the actual billing days for the months of January through July (id.). The difference between the revenues using the CRIS calculations and the weather normalized revenue from the CSS system results in the customer charge adjustment (id.). The customer-charge adjustment reduced test-year revenues by $543,219 and is required to normalize customer charge revenue collections for the test year (id.).

➢ Unbilled Sales/Revenues Adjustment

At the end of each calendar year, there is a difference between the amount of gas the Company delivered to customers (sendout) and the amount of gas that the Company billed to its customers during that period, which represents "unbilled sales" (Exh. KEDNE/AEL-1, at 10). Because the Company's weather normalization adjustment of approximately $5.5 million is based on billing data rather than sendout data, the Company must remove from test year revenue, the accrual recorded on its books for the amount of unbilled gas and associated revenue (id. at 11; see also Tr. 6. at 684-685). The Company performed this calculation in order to remove unbilled revenue that was booked for accounting purposes during the test year (Tr. 6, at 676; see also Exh. AG-8-48). The Department's precedent provides for companies to adjust test-year revenues associated with unbilled revenue. See D.T.E. 02-24/25, at 73.

For accounting purposes, the Company calculates its unbilled gas costs and revenues each month by multiplying an overall Company average gas cost and billing rate to the difference between billing sales volumes and sendout volumes (id.; Tr. 6, at 677). This estimate is trued-up each summer when the difference between sendout and billing sales is not affected by the weather (Exh. KEDNE/AEL-1, at 11; Tr. 6, at 681, 682; Exh. AG-8-40). To calculate unbilled revenues for December 2002, the Company subtracted gross unbilled volumes from December 2001 from the gross unbilled volumes for December 2002 (id.; Tr. 6 at 612-613, 685-686). The difference was then multiplied by the Company's average billing rate[24] to determine unbilled revenues, and the average gas cost rate to determine unbilled gas costs (Exh. KEDNE/AEL-1, at 11; Tr. 6, at 678-679)).

In the test year, the Company's unbilled net revenue was $4,681,950 ($15,926,040 of unbilled revenue less unbilled gas cost of $11,244,090) (Exh. KEDNE/AEL-1, at 11-12; Exh. KEDNE/AEL-3; Tr. 6 at 679-680, 688). The Company used this same methodology in calculating revenues in compliance filings under the first term of the PBR plan (Exh. KEDNE/AEL-1, at 11; Tr. 6, at 680-681; see also Boston Gas Company, D.T.E. 01-74). Therefore, consistent with Department precedent, the Company reduced test-year revenues by $15,926,040 and test-year gas costs by

[24] The Company's average billing rate was calculated by determining the Company's average margin, minus any customer-charge revenues, on a rate-class by rate-class basis (Tr. 6, at 613). This resulted in a weighted average margin, less any margin associated with customer-charge revenues (id.).

$11,244,090 to eliminate the unbilled sales accrual booked during the test year (Exh. KEDNE/AEL-1, at 11, Exh. KEDNE/AEL-2, at 9; Exh. KEDNE/AEL-3; Exh. AG-19-1; Exh. AG-19-2; see also D.T.E. 01-74 (2001)).

➢ Annualized Late Payment Charges adjustment

In 2002, revenues associated with late-payment charges totaled $479,721 (Exh. KEDNE/AEL-1, at 12). Because of incorrect programming, the CRIS system initially understated the late-payment charge revenues for 2002 (id.; Tr. 6, at 690; Exh. AG-6-6; Exh. DTE-1-30). Because the late-payment charges booked in the test year are not annualized, the Company substituted the actual late-payment charges incurred from July 2001 to June 2002 as a proxy for the annual late payment charges in 2002 (Exh. KEDNE/AEL-1, at 12; Exh. AG-6-6). The actual late-payment charges from July 2001 to June 2002 were $1,118,138 (Exh. KEDNE/AEL-1, at 12; Exh. AG-6-6; Exh. DTE-1-31). Since the test-year included $479,721 in late payment charges, the Company increased test-year revenues by $638,418 to reflect the annualized late-payment revenue level (id., Exh. KEDNE/AEL-2, at 1).

➢ Weather Stabilization Adjustment

During the test year, the Company entered into an arrangement with J. Aron and & Company to mitigate the effect of weather volatility (Exh. KEDNE/AEL-1, at 12; Exh. AG-8-41). Because the weather was colder than normal for the period covered by this arrangement, the Company experienced a net pay-out in the test year (Exh. KEDNE/AEL-1, at 12). To account for this payout, the Company reduced its booked revenue during the test year by $2,970,000 (id.). Therefore, in determining test year revenues for ratemaking purposes, the Company increased test-year revenues by $2,970,000 (id. at 13; AEL-2, at 1).

➢ PBR Revenue Adjustment

The Company reduced its test-year revenues associated with revenues booked during the test-year associated with the Department's ruling in Boston Gas Company, D.P.U. 96-50-D (2000) (Exh. KEDNE/AEL-1, at 13; Exh. AG-19-6). In that ruling, the Department issued a finding that would have increased the Company's Accumulated Inefficiencies factor contained in the price-cap formula in the Company's then-effective PBR plan (id.). The Company appealed the Department's decision to the Supreme Judicial (the "SJC") (id.).[25]

After receiving a stay from the SJC in February 2001, the Company deferred booking the revenue collected by the Company in the subsequent annual periods covered by the PBR plan because the Company's rates were collecting revenue without giving

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[25] Based on a previous appeal by the Company to the SJC of the Department's prior findings in D.P.U. 96-50-C (Phase I) (1996) with regard to the justification for a 1 percent Accumulated Inefficiencies factor, the SJC remanded the issue to the Department in 1999 (Tr. 7, at 772; Exh. AG-19-6). Between the time of the 1999 remand and the Department's January 2001 decision in D.P.U. 96-50-D in 2001, the Company did not account for an Accumulated Inefficiencies factor of 1 percent in its revenue collections, a decision based on the Department's approval of the Company's rates pending the outcome of the remand (id.; Exh. AG-19-6). Upon the Department's ruling in January 2001 that Accumulated Inefficiencies factor should be set at 0.5 percent, the Company appealed that decision to the SJC (Tr. 7, at 773; Exh. AG-19-6), but temporarily began billing rates to customers that included the Accumulated Inefficiencies factor of 0.5 percent (RR-DTE-18). This billing was stopped as of February 16, 2001, when the Company received a stay of the Department's decision (id.) From that date on, the Company reinstated the rates previously approved by the Department for effect as of November 1, 2000, which did not include the Accumulated Inefficiencies factor (id.). Moreover, the Company deferred booking revenues that might be necessary to return to customers if the SJC ruled in the Department's favor (Tr. 7, at 773; Exh. AG-19-6). The Company did not bill customers or otherwise charge customers for the revenues that were lost during the month of February 2001 as a result of the rates that became effective on February 1, 2001, including the Department's 0.5 percent Accumulated Inefficiencies factor; nor is the Company proposing to recover those costs in this proceeding (id.). Contrary to an assumption made by the Attorney General, the Company did not apply the PBR adjustment for the elimination of the accumulated inefficiencies factor retroactively (Exh. AG-19-8).

effect to the increased Accumulated Inefficiencies factor (id.; Tr. 7, at 716; see also RR-DTE-18).[26] However, on March 7, 2002, the SJC vacated the Department's ruling, thus allowing the Company to book the deferred revenue last year (id.). This booking of 2001 revenues in 2002 resulted in increased test-year revenues, which the Company adjusted in order to determine revenue for ratemaking purposes (id.; RR-DTE-18). Accordingly, the Company adjusted its test-year revenues by $3,864,000 to remove the revenue booked in the test year that was applicable to deferred revenue from prior years (id.; AEL-2, at 1; Exh. AG-8-42; RR-DTE-18).

➢ DSM Incentive Adjustment

The Company removed from test-year revenues that amount of revenue recorded by the Company in relation to the incentives it achieved on the successful implementation of its demand side management programs (Exh. KEDNE/AEL-1, at 14; Exh. AG-8-43; Exh. AG-19-30). The adjustment was justified because DSM expenses and incentives are not accounted for in base rates. See Essex County Gas Company, D.P.U. 87-59, at 6 (1987).

The Company noted during evidentiary hearings that the $1.058 million in revenues relating to the DSM incentive represents DSM incentive revenues for the period November 2001 through October 2002, as well as the period November 2002 through October 2003 (Tr. 6, at 694). Although not strictly a calendar-year incentive figure, because the amount of $1.058 million was booked during 2002 and is not properly

26 As noted during evidentiary hearings, the Company did not begin deferring revenues in this manner until mid-February 2001, which was after the Department's decision in D.P.U. 96-50-D and the Company's subsequent receipt of a stay by the SJC of the Department's decision (Tr. 7, at 717).

included in ratemaking revenues, the Company removed the same amount from its test-year revenues (id. at 694-695, 697, 700; RR-DTE-25). Accordingly, consistent with Department precedent, the Company reduced its test year revenues by $1,058,800 (id.; AEL-2. at 1; RR-DTE-25).

➢ Energy Efficiency Revenue Adjustment

The Company removed from test-year revenues the amount billed to customers for the state-wide Energy Conservation Service ("ECS") Program (Exh. KEDNE/AEL-1, at 14; Exh. AG-8-44). The revenues associated with the Company's participation in this program are collected through surcharges and not base rates. See Essex County Gas Company, D.P.U. 87-59, at 6 (1987). Accordingly, consistent with Department precedent, the Company reduced its test year revenues by $495,356 relating to ECS Program costs (id.; AEL-2, at 1; Exh. AG-8-44).[27]

➢ Non-Firm Revenue Adjustment

The Company removed from test-year revenues the amount of revenue billed to non-firm customers under interruptible sales and interruptible transportation (Exh. KEDNE/AEL-1, at 14; Exh. AG-8-21; Exh. AG-8-45). This adjustment reduces test-year revenues by $6,274,641 (id.; AEL-2, at 1).

[27] The Company made a corresponding adjustment to its Cost of Gas (see Exh. KEDNE/AEL-1, at 15; Exh. KEDNE/AEL-3; Tr. 6, at 701). During the proceeding, the Company corrected the dollar amount that should be adjusted from its Cost of Gas relating to ECS costs ($495,356, rather than $356,857) (Exh. DTE-4-58). The Company explained that its original Cost of Gas adjustment figure relating to ECS costs arose as a result of the Company's billing system conversion during the test year (Tr. 6, at 701). The Company also made corrections to its Cost of Gas adjustments relating to Broker Revenues and Non-Firm Revenues (id., at 702; Exh. DTE-4-58). The corrections also related to the Company's billing system conversion (Exh. DTE-4-58; see also RR-DTE-17).

➢ Broker Revenue Adjustment

The Company removed from test–year revenues the amount of revenue billed to third party gas suppliers (brokers) (Exh. KEDNE/AEL-1, at 15). Third party gas suppliers are billed when the gas consumed by their transportation customers exceeds the gas the brokers delivered to the Company's gate stations (id.). This adjustment reduced test-year revenues by $4,261,765 (id.; AEL-2, at 1; Exh. AG-8-46).

➢ Cost of Gas Adjustments

In addition to adjustments made to the Company's gas operating revenues, the Company made several adjustments to its test year gas costs (Exh. KEDNE/AEL-1, at 15; Exh. KEDNE/AEL-3). These adjustments relate specifically to accounting entries, and not to the Company's CGA or LDAC (Exh. DTE-4-59). Ms. Leary testified that the Company reduced test-year Cost of Gas for gas costs associated with: (1) Unbilled Sales; (2) Non-Firm gas costs; (3) Broker Revenues; (4) ECS costs; and (5) CGA recoverable costs (Exh. KEDNE/AEL-1, at 15; Exh. KEDNE/AEL-3). The Company increased the test year Cost of Gas for: (1) Non-Firm margin retention; and (2) DSM Incentive Costs (Exh. KEDNE/AEL-1, at 15; Exh. KEDNE/AEL-3; see also Exh. DTE 4-62).

3. The Company's Revenue Adjustment For the Termination of the Exelon Contract is Appropriate and Consistent with Department Precedent

The Attorney General contests only one of the Company's proposed revenue adjustments, which is the reduction to test-year revenues to account for the loss of the special contract with Exelon New England Holdings, LLC ("Exelon"). Specifically, the Attorney General argues that the revenue loss is not known and measurable because (1) there is no evidence that the contract will not be extended again; (2) the loss of the

Exelon revenues does not constitute a significant adjustment beyond the "ebb and flow" of customers; (3) the revenue loss is offset by a new contract involving another unit at the Mystic Station; and (4) the Company has not provided an explanation for the disparity between the revenues associated with the terminating contract and the new contract with Distrigas (Attorney General at 35-37).

As discussed below, the Company's proposal meets the Department's standard for a post-test year adjustment. In the test-year, non-tariff firm transportation contracts (i.e., "special contracts) revenues totaled $16.6 million and, consistent with Department precedent, the Company incorporated these revenues into the revenue requirement (Exh. KEDNE/AEL-1 at 9; Tr. 6, at 671; see also D.P.U. 96-50 (Phase I) at 345-346).[28] However, test-year revenues also include approximately $3.7 million in revenues relating to the Company's contract with Exelon (Exh. KEDNE/AEL-1, at 9; Exh. KEDNE/AEL-2, at 8; Exh. AG-6-5). Under this contract, the Company currently provides firm transportation service to Exelon New Boston (located in South Boston) and Mystic 7 (located in Everett) (Exh. KEDNE/AEL-1, at 9).

On March 25, 2003, the Department approved an amendment to the original agreement (GC 03-03), which provides for a termination date of March 31, 2004, which is prior to the midpoint of the rate year (id.). Exelon has informed the Company that it will not renew the existing contract, because it will commence operation of two new plants in Everett this year (id.; Exh. AG-8-39). The most recent amendment to the

28 The $16.6 million figure represents the test-year revenue from the Company's "special" off-tariff contracts, including the Exelon Contract. That figure is the amount reflected in the Company's cost of service (Tr. 6 at 672). If gas costs for the Company's "Rate 24" customers are added in, the total revenue from all of the Company's non-tariff, firm transportation customers is approximately $19 million (id.; Exh. AG-19-12 (**CONFIDENTIAL**).

original agreement provides that Exelon may terminate its agreement with the Company upon 60 days advance notice (or by March 31, 2004) (id.).

To determine the revenue adjustment associated with the termination of the Exelon Contract, the Company considered the new revenue that it will receive as a result of a new agreement between Distrigas and the Company to transport gas to Exelon's new Mystic 8 and 9 units (Exh. KEDNE/AEL-1, at 10; Exh. KEDNE/AEL-2, at 8, RR-AG-22; Tr. 6, at 618-620). The Distrigas Agreement was approved by the Department in GC-01-04, with service commencing on March 1, 2002 (Exh. KEDNE/AEL-1, at 9-10). Under this contract, Boston Gas provides transportation service from the Distrigas facilities to the Exelon facilities under a contractual arrangement with Distrigas, and Distrigas provides a bundled supply and transportation package to Exelon.[29]

The Department has allowed adjustments in test-year revenues for post-test year changes in consumption or customer numbers that: (1) represent a known and measurable increase or decrease to test year revenues; and (2) constitutes a significant adjustment outside of the normal "ebb and flow" of customers. D.T.E. 02-24/25, at 80; D.T.E. 99-118, at 14, 20; D.P.U. 96-50 (Phase I) at 76, citing D.P.U. 95-118, at 130, D.P.U. 1270/1414, at 20 (see also Exh. DTE-5-13). The Company's proposed adjustment meets this standard.

First, the termination of revenues associated with the Exelon contract is highly likely based on actions taken by Exelon. Second, the seventh amendment to the Exelon Contract dated February 28, 2003, and which extended the contract through

[29] The transportation service provided by Boston Gas would not vary in price or in nature if the service were provided directly to Exelon. As structured, Distrigas must pay Boston Gas for its demand charges, whether or not the Exelon plants operate, and therefore, Distrigas is a stronger contractual partner for the Company to have. Exh. AG-1-99.

March 31, 2004, includes the previously referenced 60-day termination option (Exh. KEDNE/AEL-1, at 10; RR-AG-25; Tr. 6, at 616, 621, 666, 668). Therefore, upon the granting of 60 days notice, Exelon may terminate the contract prior to March 31, 2004. In addition, the Company submitted documentation referencing public pronouncements by Exelon of its intent to close its New Boston facility (Exh. AG-8-39).[30] Accordingly, based on the evidence presented by the Company regarding the discontinued operation of Exelon's New Boston and Mystic 7 facilities on a full-time basis, the Department should find that the termination of the Exelon Contract represents a known change to the Company's test year revenues.

In addition, the revenues associated with that loss are measurable because the Company can determine its 2002 revenues associated with the Exelon contract, and use those revenues as a proxy for revenues that it would have received under the Exelon contract in the future.

Moreover, the Company demonstrated that the revenue adjustment associated with the Exelon contract will be significant. The Company compared the $3.7 million in revenues associated with the Exelon contract to its total revenues from non-core customer revenues and determined that the revenues from the Exelon contract represented approximately 22 percent of the Company's revenues from special contracts (Exh. AG-19-12 **CONFIDENTIAL**; Tr. 7, at 776). In addition, Ms. Leary testified that the elimination of the revenues associated with the Exelon Contract would have a 5.2 percent

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30 Although it is unclear whether Exelon intends to close the Mystic 7 facility, if Exelon opted to terminate the Exelon contract because of a decision to close only its New Boston facility, the revenues associated with both the New Boston facility and Mystic 7 facility would be lost, at least as they relate to the Exelon contract (RR-DTE-13; RR-AG-25). Unless and until Exelon decided to enter into a new contract with the Company to serve Mystic 7, the Department should consider the revenues lost from both Mystic 7 and New Boston as a result of any termination of the Exelon Contract as a known and measurable post test-year adjustment.

impact on the Company's net operating income before taxes (Tr. 7, at 776). Moreover, the margin associated with the Exelon Contract is three and a half times larger than that of the contract's replacement (the Distrigas contract) (id.; see also Exh. KEDNE/AEL-2, at 8). Accordingly, the Company demonstrated that the revenues associated with the Exelon Contract were both: (1) significant; and (2) outside the normal "ebb and flow" of customers.

Therefore, because the termination of the Exelon Contract as of March 31, 2004 represents a known and measurable change to the Company's test-year revenue, and such change constitutes a significant adjustment outside of the normal "ebb and flow" of customers, the Company adjusted test-year revenues by $3.7 million to remove the revenues billed under the terms of the agreement in 2002 (Exh. KEDNE/AEL-1, at 10, Exh. KEDNE/AEL-2, at 8). In addition, the Company increased test-year revenues by the annualized amount of revenues associated with the Distrigas contract (Exh. KEDNE/AEL-1, at 10, Exh. KEDNE/AEL-2, at 8; Tr. 6, at 618-620). These calculations result in a net reduction to test-year revenues of $3,446,482 (Exh. KEDNE/AEL-1, at 10, Exh. KEDNE/AEL-2, at 8).

C. EXPENSE ADJUSTMENTS

1. The Company Has Proposed O&M Expense Adjustments That Are Consistent with Department Precedent.

In order to establish representative expense levels for the determination of the revenue deficiency and the establishment of base rates, the Company proposed approximately 23 adjustments based on known and measurable changes to the test-year O&M expense level on the Company's books as of December 31, 2002. See, Exh. KEDNE/PJM-2 [rev.2]. Of those 23 adjustments, the Attorney General and MOC have challenged a total of 10. In addition, the Attorney General and MOC challenge the recovery of the Company's test-year promotional expenses, although the Company has not proposed a test-year adjustment in relation to this expense category.

The post-test year expense adjustments that are not disputed in this case are briefly summarized below with references to supporting record evidence. These adjustments include:

(i) Union Wages and Wage Increases
(ii) Transition to Variable Pay
(iii) Dental Coverage
(iv) Health Insurance
(v) Insurance Expense
(vi) Postage Increase
(vii) Strike Contingency Expense
(viii) Severance Adjustment
(ix) CGA Recoverable Costs
(x) Lobbying Expense
(xi) Fines
(xii) Adjustments to Service Company Expenses
(xiii) Charitable Contributions
(xiv) Inflation Adjustment

In Section II.C.3, below, the Company responds to the expense-item claims of the Attorney General and MOC. No other intervenors commented on the Company's expense adjustments. These adjustments include:

(i) Incremental Cost Adjustment
(ii) Non-Union Wages and Wage Increases and Incentive Compensation
(iii) Pension Expense
(iv) Incremental Cost Adjustment
(v) Rate Case Expense
(vi) Property Leases
(vii) Gain on Sale of Utility Property
(viii) Bad-Debt Expense
(ix) Advertising Expense

2. The Department Should Accept the Non-Contested Post Test Year Adjustments Proposed by The Company

(i) Union Wages and Wage Increases

To recover post test-year union payroll adjustments, the Department requires companies to meet three conditions: (1) the proposed increase must take effect before the mid-point of the rate year; (2) the proposed increase must be known and measurable (i.e., based on signed contracts between the union and the company); and (3) the proposed increase must be demonstrated to be reasonable. Fitchburg Gas & Electric Light Company, D.T.E. 02-24/25, at 89 (2002); Boston Gas Company, 96-50 (Phase I) at 43, Massachusetts Electric Company, D.P.U. 95-40, at 20 (1995); Cambridge Electric Light Company, D.P.U. 92-250, at 35 (1993).

As of December 31, 2002, the Company's total union payroll expense in the test year was $46,729,199. Consistent with Department precedent, the Company has adjusted its test-year payroll expense to reflect known and measurable changes that will take effect through the midpoint of the rate year, which is April 30, 2004 (Exh. KEDNE/PJM-1 at 7). These adjustments are designed to: (1) annualize test-year payroll costs to reflect wage and salary increases that became effective during the test year; (2) incorporate payroll increases that became effective on April 1, 2003; and (3) incorporate payroll increases that take effect prior to the midpoint of the rate year (i.e., by April 30, 2004) (id.). The adjustments relate to direct wage expense and allocated wage expense for Service Company employees who perform services on behalf of Boston Gas. In total, the Company is requesting to increase test-year union wage expense by $2,830,121.

The Company's proposed adjustment for union wage increases is consistent with Department precedent for the following reasons. First, under the Company's current collective bargaining agreements, Boston Gas is committed to payroll increases for union personnel in 2003 of between 3.0 percent and 3.75 percent (Exh. KEDNE/JCO-2). In addition, two of the Company's collective bargaining agreements mandate payroll increases of 3.0 percent prior to the midpoint of the rate year (i.e., April 30, 2004) (id.). (Exh. KEDNE/PJM-1, at 8; Exh. KEDNE/PJM-2, at 6; Exh. KEDNE/JCO-1 at 6; Exh. KEDNE/JCO-2; see also Exh. AG-1-42(a) through (l)).

In order to demonstrate that the proposed union payroll adjustments are reasonable, the Company provided two surveys to compare union wage expense levels and payroll increases. See e.g. Bay State Gas Company, D.P.U. 92-111, at 98 (1992). First, the Company provided the Department with the American Gas Association's ("AGA") 2002 Non-Exempt Compensation Survey of participating local distribution companies in the Northeast (Exh. KEDNE/JCO-1, at 16; Exh. KEDNE/JCO-7; Exh. AG-10-1 (supp.)). The Company used the AGA Survey to compare the median hourly wage rates and bonuses paid by the participating utilities to the average hourly rates and bonuses paid to Boston Gas union employees (Exh. KEDNE/JCO-1, at 16; Exh. KEDNE/JCO-7; Exh. AG-10-1 (supp.); Tr. 16, at 2080, 2084, 2086).[31] The AGA survey demonstrates that the median hourly rate of $24.13 paid by other Northeast utilities (with bonuses of $1,900 on average for utilities that paid bonuses), is consistent with the average hourly rate paid by the Company per position of $24.39, with bonuses of $150,

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31 Mr. Orlando clarified during the July 24 evidentiary hearing that the Company's union employee compensation comparison using the 2002 AGA Survey was between the "median" hourly rate and annual bonus for the participating Northeast utilities and the "average" hourly rate and bonus paid by Boston Gas (Tr. 16, at 2086). Mr. Orlando attributed confusion regarding the Company's union employee compensation comparison to an incorrect heading in Exh. KEDNE/JCO-7 (id.). However, he noted that the Company's methodology of comparing Boston Gas' employee compensation data to the AGA "median" data is proper, because the median reflects the 50th percentile data, meaning that half of the companies in that data cut pay less than the median figure and half of them pay more (id.).

as compared to (Exh. KEDNE/JCO-1, at 16; Exh. KEDNE/JCO-7). Accordingly, the Company's average hourly wages and hourly wages plus bonuses are either roughly equivalent to the median union compensation rates for the Northeast utilities which participated in the AGA Survey (id.). RR-DTE-73.

In addition, the Company provided the Department with a comparison of the historical wage increases (on a percentage basis) for union employees of the eleven New England local distribution companies for the period 1993 through 2003 (Exh. KEDNE/JCO-1, at 16; Exh. KEDNE/JCO-8). The comparison demonstrated that the Company's contractual wage increase in 2002 of 3.0 percent is within the range of 2.5 to 4.0 percent for other New England local distribution companies (id.). Likewise, the wage increases in 2003 for Boston Gas' union employees were at 3 percent, the same as other New England local distribution companies (id.). Accordingly, the Company demonstrated that its union payroll adjustments are reasonable. Moreover, as stated above, the Company demonstrated that its union payroll adjustments met the other two conditions for inclusion in the Company's cost of service which are that the adjustments (1) will take effect before the mid-point of the rate year; and (2) are known and measurable. Therefore, the Department should allow the Company to include its union payroll adjustments in its cost of service.

(ii) Transition to Variable Pay

KeySpan is nearing completion of a three-year transition plan to standardize the wage and salary structure for non-union employees of the regulated gas distribution companies in Massachusetts and New York (Exh. KEDNE/PJM-1, at 12). The payroll structure for non-union employees is composed of a base-salary component and a variable component. To achieve the standardized structure, payroll increases for Boston

Gas non-union employees are less than the payroll increases in New York, while the percentage of incentive compensation for Boston Gas non-union employees is increasing. The calendar year ending December 31, 2003 represents the final year of the transition plan (id.).

In accordance with the plan, base wages for Boston Gas non-union employees will increase in 2003 at a rate that is 1 percent less than the increase for New York non-union employees. To reflect this known and measurable change, the Company has made an adjustment to increase test-year target incentive-compensation costs in the amount of $297,372, which represents $211,192 associated with Service Company non-union employees and $86,180 associated with Boston Gas non-union employees (both adjustments exclusive of capitalized amounts). Of the total compensation adjustment for the Service Company, $434, 243, or approximately 68.10 percent, is allocated to Boston Gas based on the Massachusetts formula of revenues, assets and O&M expense, excluding the cost of gas. These calculations are presented in Exhibit KEDNE/PJM-2, at 9 (id. at 13).

(iii) Dental Coverage

The Department requires that test-year health and dental-care expense and post-test year adjustments be (1) known and measurable and (2) reasonable in amount. D.P.U. 96-50 at 46; D.P.U. 95-40, at 25; North Attleboro Gas Company, D.P.U. 98-86, at 8 (1986). In addition, the Department requires that utilities demonstrate efforts to contain their health care costs. D.P.U. 96-50, at 46; Massachusetts Electric Company, D.P.U. 92-78, at 29 (1992). Therefore, the Company is allowed to adjust test-year dental expenses to include known and measurable increases occurring prior to the midpoint of the rate year. The Company adjusted the test-year dental expense by $51,432 to reflect documented increases in costs for dental coverage for both union and non-union employees in 2003 (Exh. KEDNE/PJM-1, at 13; Exh. KEDNE/JCO-1, at 13; Exh. KEDNE/JCO-6). The adjustment is based on the analysis of cost increases for the plan overall and for each individual employee (Exh. KEDNE/PJM-1, at 13).

Based on this analysis, the annualized dental expense for 2003 is $747,859 for direct Boston Gas employees and $281,087 for Service Company employees (Exh. KEDNE/JCO-1, at 13). This results in an increase to the test-year cost of service of $51,432 for direct and allocated employees (id.; Exh. KEDNE/PJM-2, at 10). The Company's cost-containment measures for health and dental expense are described in Exhibit KEDNE/JCO-1, at 12-14 and related information requests. AG-1-52. Therefore, the Department should allow the Company to include its dental-care expense adjustment in its cost of service.

(iv) Health Insurance

The Department's standard for recovery of health-care expenses is the sames as that for dental expense. Under Department precedent, adjustments for post-test year increases in health-care insurance costs must be: (1) known and measurable; and (2) reasonable in amount. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 107 (2002); D.P.U. 96-50 (Phase I), at 45-46; North Attleboro Gas Company, D.P.U. 86-86, at 8 (1986). In addition, the Department requires that utilities demonstrate efforts to contain health care costs. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25 (2002); D.P.U. 96-50 (Phase I).

To satisfy this standard, the Company provided notices of its 2003 medical insurance premium increases. Exh. KEDNE/PJM-1, at 14; Exh. KEDNE/JCO-5; Exh.

AG-51 [supp.]. The Company also provided an analysis outlining the specific insurance premiums that the Company will pay in 2003 on an individual employee basis (id.). The analysis shows an increase to the test-year cost of service of $1,128,502 for direct and allocated employee health-care expenses (Exh. KEDNE/PJM-1, at 14).

Second, the Company demonstrated its efforts to contain health care costs. Specifically, the record shows that KeySpan obtains medical benefits from a variety of service providers and instituted a number of changes to reduce premium costs, such as increasing employee co-payments, modifying benefits and introducing self-insurance programs (Exh. KEDNE/JCO-1, at 12-15; Exh. AG-1-52; Exh. AG-10-34; Exh. DTE-2-14; Exh. DTE-2-18; Exh. DTE-2-24). Second, the Company provided documentation that establishes that the increases in medical-insurance premiums paid by the Company are less than those experienced in the marketplace generally (Exh. KEDNE/JCO-1, at 12-15; Exh. AG-1-52; Exh. AG-10-34; Exh. DTE-2-14; Exh. DTE-2-18; Exh. DTE-2-24).

Third, the Company initiated a self-insurance plan for drug coverage for its New England employees, including Boston Gas, rather than continuing to pay for drug coverage within the monthly premiums for individual and family healthcare plans (Exh. KEDNE/JCO-1, at 12). The record indicates that approximately five percent of the incremental cost of including drug coverage in the individual and family healthcare plans offered to employees could be defrayed as a result of the implementation of the self-insurance program (id.). The estimate of five percent cost avoidance was determined by the Company's vendor, Caremark, which is the fourth largest pharmacy-benefit manager in the United States (Exh. AG-10-34).

Accordingly, the Department should accept the Company's proposed post-test year adjustment to increase the cost of service by $1,128,502 for direct and allocated employees health-care expenses (Exh. KEDNE/PJM-1, at 14).

(v) Insurance Expense

The Company has adjusted test-year insurance expense by $607,287. Exh. KEDNE/PJM-12, at 13. Under Department precedent, companies may include the cost of liability insurance as a reasonable cost of service provided that the costs are based on an executed agreement. See North Attleboro Gas Company, D.P.U. 86-86, at 8-10 (1986); Colonial Gas Company, D.P.U. 84-94 (1984). To establish the appropriate level of insurance expense, the Company performed a policy-by-policy evaluation to compare the premium costs associated with each insurance policy in the test year to the premium costs for each policy that has been renewed for 2003 (Exh. KEDNE/PJM-1, at 16; Exh. KEDNE/PJM-2, at 13; Exh. KEDNE/PJM-4). The Company also documented the reasons for the more substantial increases in insurance expenses associated with the renewal of the Company's liability policies (Exh. DTE-2-10; Tr.). The record indicates that there are several factors driving the increase in insurance premiums, including the terrorist attacks on September 11, 2001 and the effect on the market subsequent to the bankruptcies of Enron and Kmart (id.).

The insurance-premium costs allocated to Boston Gas by the Service Company were separately calculated based on applicable allocation percentages, which vary by policy type, and are designed to be consistent with the nature of the insurance cost being allocated (e.g., general liability insurance premiums are allocated based on the number of employees) (Exh. AG-1-61; Exh. AG-1-62).

Accordingly, the Department should accept the Company's proposed post-test year adjustment to increase the cost of service by $607,287 for direct and allocated insurance expenses. Exh. KEDNE/PJM-2, at 13.

(vi) Postage Expense

The Company adjusted its test year postage expense of $2,423,592, to annualize the 10.83 percent increase in postal rates that became effective on July 1, 2002. Exh. KEDNE/PJM-1, at 18; Exh. KEDNE/PJM-2, at 16. This results in an increase to the test-year cost of service of $124,491 (id.).

(vii) Strike Contingency Expense

The Department has found that preparation for a potential labor strike is essential to ensure that the Company continues to operate in the event of a strike. Berkshire Gas Company, D.T.E. 01-56, at 65 (2002). The Department has further stated that the Company will need to update or develop new strike contingency plans each time it negotiates a labor contract, and therefore, these types of expenses are recurring. Id. The Company incurred strike contingency expense during the test year of $321,865 for contracts that expired March 17, 2003 and were ultimately renegotiated without a work stoppage (Exh. KEDNE/PJM-1, at 19; Exh. KEDNE/PJM-2, at 17). The Company deferred the cost of its strike contingency expense until such time as it could be amortized for recovery over the term of the collective bargaining agreement (Exh. KEDNE/PJM-1, at 19). Consistent with Department precedent, the Company has normalized the strike contingency amount over four years, which is the length of the union contract, and has increased the test-year cost of service in the amount of $80,466 (id.).

The Company's strike contingency costs include: (1) hiring outside contractors to train non-union staff to operate the Company's business in the event of a strike; (2) implementing security measures, such as changing locks to secure the assets of the Company, installing fencing and communications equipment and hiring security personnel; and (3) initiating a customer information program. Exh. KEDNE/PJM-1, at 19. The record shows that this expenditure was an integral part of the Company's strategy to minimize labor costs while assuring reliable service to customers in the event of a labor strike. Exh. DTE-2-6. Also, if union negotiators are aware that management is prepared to operate the business in the event of a strike, the Company's negotiating power is strengthened and management will be likely to hold union wages to a reasonable level (id.). Without measures to protect the Company's non-union employees and assets, a strike could result in a disruption of service to customers and jeopardize employees and Company property (id.).

The Department has found that strike contingency expenses are recurring and properly included in a company's cost of service, and therefore, the Department should approve Boston Gas' adjustment of $80,466 for strike contingency costs.

(viii) Severance Adjustment

The Company has proposed to increase its test year O&M expense by $250,000 to eliminate the effect of an adjustment the Company made to its books to reverse amounts associated with the accrual of severance expense. Exh. KEDNE/PJM-1, at 22. The Company implemented a severance program in order to reduce its workforce and allow for the consolidation of job functions as work was transferred to New York and eventually organized within the Service Company (Exh. KEDNE/PJM-1, at 22; Exh.

DTE 2-34). In total, 30 Boston Gas employees elected to participate in the severance program since 2000. Exh. DTE-2-34.

This adjustment does not affect the revenue requirement. As explained on the record, under Generally Accepted Accounting Principles ("GAAP"), when a company incurs a liability that is known and measurable, it is required to record that liability on its books (Exh. DTE 2-35). If the amount is not known, but is reasonably estimable, the company is also required to record the estimate on its books (id.). Following the KeySpan/Eastern Enterprises merger in November 2000, the Company had a known liability, which was reasonably estimable at the time (id.). Therefore, the Company booked an accrual to reflect the liability associated with the severance program. However, as shown on the record, the accrual exceeded the actual cost and, as a result, the Company made an entry on its books in 2002 to reverse the remaining liability of $250,000, which reduced O&M expense by $250,000 in the test year. The Company has proposed eliminating the effect of the accrual by increasing test-year O&M expense by the amount of the reversal (Exh. KEDNE/PJM-1 at 22).

(ix) CGA Recoverable Costs

In D.P.U. 96-50, the Department unbundled certain costs from the Company's base rates to allow for the recovery of gas-supply related local production and storage, gas procurement and bad-debt costs through the Cost of Gas Adjustment ("CGA") factor. When incurred, these costs are recorded as O&M expenses (i.e., local production and storage expense and bad-debt expense) on the Company's books. However, in order to recover these costs during the year through the CGA, the Company makes an adjustment on the books to reduce (credit) O&M expenses and to increase (debit) the cost of gas by the amount of these expenses.

Therefore, to establish appropriate base rates in this case, the Company excluded from the test-year O&M expense the effect of the accounting entry to move these costs into the cost of gas for recovery through the CGA. Specifically, the Company adjusted test-year O&M expense by $25,588,070 to eliminate the effect of the O&M expense credit. Exh. KEDNE/PJM-2, at page 21. There is no net effect on the revenue requirement. The adjustment increases test-year O&M expense in Exhibit KEDNE/PJM-2, at page 21, and a corresponding adjustment is made to reduce the test-year cost of gas, as shown on Exhibit KEDNE/PJM-2, at page 4. As done in D.P.U. 96-50, once the level of these expenses has been established in this rate case, these costs will be removed from the base rates and recovered through the CGA.

Accordingly, the Department should approve the Company's proposed adjustment for CGA Recoverable Costs.

(x) Lobbying Expense

The Department has found that lobbying and lobbying-related activities should be removed from the Company's cost of service in the absence of a showing of direct benefits to ratepayers. New England Telephone and Telegraph Company, D.P.U. 86-33, at 101 (1989). Lobbying expenses include both actual lobbying efforts and data collection/analysis. Id.; Boston Edison Company, D.P.U. 1720, at 74-75 (1983). The Department has found that certain activities performed by the American Gas Association fall within the purview of lobbying and lobbying-related activities (e.g., communications with Congress on pending or proposed legislation and analysis of proposed legislation and regulations. Boston Gas Company, D.P.U. 88-67, Phase I, at 105-108 (1988);

Commonwealth Gas Company, D.P.U. 87-122, at 88-89 (1987); Essex County Gas Company, D.P.U. 87-59, at 49-51 (1987). Accordingly, the Company has removed that portion of the AGA dues that are attributable to lobbying activity, as well as the other direct and allocated lobbying expenses that were not recorded below the line in the test year. (Exh. KEDNE/PJM-1, at 27). The Company's adjustment reduced the test-year cost of service by $13,247 attributed to lobbying expenses (Exh. KEDNE/PJM-2, at 23).

(xi) Fines

The Company reduced the test-year cost of service by $71,150 to adjust for fines and penalties that were incurred in the test-year but are not allowed to be included in rates under the Department's precedent (Exh. KEDNE/PJM-1 at 28; Exh. KEDNE/PJM-2, at 25; Exh. KEDNE/PJM-2 [supp.] at 132-135; Exh. DTE 5-36; Exh. DTE 5-37; Exh. AG 1-83; Exh. AG 6-56).

(xii) Adjustments to Service Company Expenses

The Company reduced its test-year cost of service by $1,445,365, to reflect costs that were properly allocated to the Company by the Service Company, but are not includable in rates under Department ratemaking precedent (Exh. KEDNE/PJM-1, at 28 -29; Exh. KEDNE/PJM-2, at 26). These costs include corporate-sponsored memberships, branding and strike contingency expenses incurred by the Service Company. These costs are charged to the Boston Gas operations under the appropriate allocation formulas but have been removed from the test-year cost of service consistent with Department precedent. Commonwealth Electric Company, D.P.U. 89-114/90-331/91-80, at 79-84 (1991).

(xiii) Charitable Contributions

In the test year, the Company made charitable contributions of $303,268, which were recorded on the Company's books "below the line" (Exh. KEDNE/PJM-1, at 29; Exh. KEDNE/PJM-2, at 27). Accordingly, no adjustment to the test year cost of service was needed for charitable contributions, as it was not included in the test year cost of service.

(xiv) Inflation Adjustment

The Department allows utilities to recover an inflation adjustment that reflects the likely cost of providing the same level of service in the future as was provided in the test year. Berkshire Gas Company, D.T.E. 01-56 at 68-69 (2002); Fitchburg Gas and Electric Light Company, D.T.E. 98-51, at 100 (1999); Boston Gas Company, D.T.E. 96-50 at 112; Massachusetts Electric Company, D.P.U. 95-40 at 64 (1995). The Department permits utilities to increase their test year residual O&M by the projected GDPPID from the midpoint of the test year to the midpoint of the rate year. See Massachusetts Electric Company, D.P.U. 95-40, at 64 (1995), Cambridge Electric Light Company, D.P.U. 92-250 at 97 (1993). However, in order for the Department to allow a utility to recover an inflation adjustment, the utility must demonstrate that it has implemented cost containment measures. Boston Gas Company, D.P.U. 96-50, at 113.

Consistent with the Department precedent, the Company calculated the applicable inflation adjustment based on the increase in the Gross Domestic Product—Implicit Price Deflator from the midpoint of the test year to the midpoint of the rate year. This calculation resulted in an inflation factor of 5.25 percent (Exh. KEDNE/PJM-1, at 29; Exh. KEDNE/PJM-2, at 28-29). The Company applied the inflation factor to its residual O&M expenses of $53,118,261, resulting in a total inflation adjustment of $2,788,709.

3. The Attorney General's Claims on the Company's O&M Expense Adjustments Are Not Supported by the Record.

The claims of the Attorney General on the following issues are discussed below:

- Incremental Cost Adjustment
- Investment Tax Credit Amortization
- Pension Expense
- Property Lease Expense
- Test-Year Promotional Expense
- Advertising Expense
- Bad Debt Expense
- Dig-Safe Fines
- Gain on Sale of Utility Property
- Non-Union Compensation Levels and Incentive Compensation Increase
- Cash Bonuses
- Capitalized Employee Benefits
- Shareholder Services
- Rate Case Expense

The Company discusses each of these issues in turn below.

(i) The Company's Incremental Cost Adjustment is Consistent with, and Gives Effect to, the Department's Merger Orders.

On September 17, 1998, the Department approved the merger of Eastern Enterprises and Essex Gas Company ("Essex). Eastern-Essex Acquisition, D.T.E. 98-27 (1998). During the course of the proceeding, the joint petitioners, i.e., Eastern and Essex, explained to the Department that most, if not all, of the "corporate functions" performed by Essex management prior to the merger would be absorbed by Boston Gas following the merger, but that Boston Gas could complete these tasks without incurring any additional cost because (1) many of the functions would be completed using the more sophisticated information systems owned by Boston Gas; and (2) Boston Gas would use its own resources at a higher efficiency. At the same time, the consolidation of functions within Boston Gas provided Eastern Enterprises the opportunity to achieve cost savings on the Essex system to offset the costs that it had incurred to complete the merger and to extend a 10-year rate freeze to Essex customers. D.T.E. 98-27, at 68.

In approving the merger, the Department allowed Eastern Enterprises to retain the cost savings resulting from the merger during the rate freeze period to offset the costs of the merger. Id. At 66; D.T.E. 98-27-A, at 4. The Department also recognized that corporate and administrative functions would be consolidated within Boston Gas, but directed the joint petitioners to develop a cost-allocation system for transactions between Boston Gas and Essex. Id. at 47. In response to a Motion for Reconsideration filed by the joint petitioners, the Department clarified that the cost-allocation system would not be used for the purposes of setting rates for Boston Gas during the ten-year duration of Essex's rate plan. D.T.E. 98-27-A, at 4. In addition, the Department stated that, throughout the ten-year term of the rate plan, the joint petitioners would assign to Essex only the "incremental" costs that Boston Gas incurred to perform corporate and administrative functions for Essex, which are costs that Boston Gas would not have incurred, except for the need to serve Essex. D.T.E. 98-27, at 45; id. at 5. The Department found that this arrangement was necessary, because it would ensure that Boston Gas customers did not subsidize Essex customers and would still allow merger savings to be allocated to shareholders from the Eastern-Essex merger. D.T.E. 98-27-A, at 5.

On July 15, 1999, the Department approved the merger of Eastern Enterprises and Colonial Gas Company. Eastern-Colonial Acquisition, D.T.E. 98-128 (1999). With its approval of that merger, the Department confirmed that it would apply the same cost-allocation principle for the 10-year period of the Colonial rate plan. Therefore, the corporate and administrative functions were consolidated into Boston Gas, which in turn, was required to allocate to Colonial any incremental costs that it incurred in providing those services to Colonial. D.T.E. 98-128, at 88.

In November 2000, KeySpan acquired the operations of Eastern Enterprises, including the Boston Gas, Colonial and Essex companies. Exh. JFB-1, at 7. Because KeySpan is a registered public utility holding company under PUHCA, KeySpan is required to perform "shared services" through a service company. All of the costs incurred by the service company are assigned or allocated to the relevant operating affiliates based on cost causation principles. Therefore, KeySpan could not continue to provide shared corporate and administrative functions through Boston Gas to Colonial and Essex, and instead, the Service Company picked up the functions that Boston Gas was performing. However, aside from the change in the "service provider," no change in the nature or type of services being provided to Essex and Colonial occurred.

This case is the first base-rate proceeding for Boston Gas since the Department's rulings in the merger case. In developing the rate-case analysis for filing at the Department, therefore, the Company carefully reviewed all of the cost allocations between the Service Company and Colonial and Essex. For Colonial, all costs incurred by the Service Company are assigned or allocated to Colonial from the Service Company based on formulas reviewed by the SEC (see the response to Information Request AG-1-28). The SEC formulas do not recognize the ratemaking treatment granted to the Company by the Department in D.T.E. 98-128. Under the ratemaking treatment approved by the Department in that case, only costs that would be incremental to Boston Gas are assigned or allocated to Colonial for ratemaking purposes.

Therefore, in this case, certain costs that were incurred by the Service Company, and assigned or allocated to Colonial under the SEC formulas, were allocated to Boston Gas for ratemaking purposes. Exh. KEDNE/PJM-1, at 20. The record shows that the costs that were allocated to Boston Gas were costs that would have been incurred by the Service Company on behalf of Boston Gas, regardless of Colonial's participation. These costs are listed in Exhibit KEDNE/PJM-2, at page 18. Costs that were assigned or allocated to Colonial under the SEC formulas, and are costs that would not have been incurred by the Service Company but for the need to serve Colonial, were appropriately allocated to Colonial and no further adjustment is needed in this case.

To determine whether costs assigned or allocated to Colonial were incremental, the Company reviewed each project activity and cost item relating to Colonial. A listing of all costs assigned or allocated to Colonial was provided in Exhibit KEDNE/PJM-2 [supp.] at pages 88-96. This listing also highlights whether a particular line item was treated as incremental or non-incremental, with non-incremental being allocated to Boston Gas for ratemaking purposes.

For each cost item, the Company applied the following criteria to determine whether costs were incremental or non-incremental:

(1) Category 1: If the costs associated with a project activity are directly assigned to Colonial, then the costs are incremental to Boston Gas and were not allocated to Boston Gas for ratemaking purposes;

(2) Category 2: Costs that are related to activities such as field marketing, leak survey, meter operations, or similar activities, were deemed to be incremental to Boston Gas and were not allocated to Boston Gas for ratemaking purposes;

(3) Category 3: If the costs are related to general and administrative activities, corporate management, finance, human resources, legal and similar activities and are not directly assigned, then the costs were

> determined to be non-incremental to Boston Gas and were allocated to Boston Gas for ratemaking purposes.

(Exh. AG-11-1).

In reviewing these costs categories to determine non-incremental costs, the Company recognized that a portion of the "Category 2" costs are general and administrative costs that may or may not be incremental to Boston Gas. However, the Company considered all of these costs to be "incremental" to Boston Gas, so that the "non-incremental" costs allocated to Boston Gas represents a conservative grouping.

The case is different for Essex. The SEC formulas do not recognize Essex as an entity that is distinct from Boston Gas, and therefore, no costs are assigned or allocated to Essex under the SEC formulas. However, consistent with the Department's ratemaking treatment relating to the merger, the Company performed the same three-step analysis outlined above. The results of this analysis were as follows:

- ⇨ Category 1: Costs associated with a project activity that are directly assigned (100 percent) to Essex were considered to be incremental to Boston Gas and properly assigned to Essex. In addition, costs that were allocated to Boston Gas in 2002 (under the SEC methodologies), but incurred only because of the existence of Essex, were reallocated to Essex for ratemaking purposes in this case. These costs, in combination with the directly assigned costs totaled approximately $1.4 million. Exhibit AG-11-9 shows the derivation of this amount and a reference to the supporting workpapers.

- ⇨ Category 2: As noted above for Colonial, the Company identified costs relating to activities such as field marketing, leak survey, meter operations, or similar activities, that were deemed to be incremental to Boston Gas. These costs totaled $425,031. Unlike Colonial, these costs are not allocated to Essex through the SEC allocation methodologies. Therefore, to identify these costs, the Company first identified the Category 2 costs allocated to Boston Gas that paralleled the Projects and Project Activities allocated and deemed incremental to Colonial. The Company then applied the allocation percentages that would have applied to Essex had the costs been allocated by the Service Company. The resulting listing and the allocation percentages applied are provided in AG-11-1. The Company then reviewed this listing to remove all general and administrative costs because the relative size of the Essex operations to the Boston Gas operations generated no incremental costs for Boston Gas. The Company also removed postage costs, which were directly assigned to Essex. The costs that were deemed incremental to Boston Gas are listed in the right-hand column of Exhibit AG-11-1.

⇨ Category 3: If the costs were related to general and administrative activities, corporate management, finance, human resources, legal and similar activities, and were not directly assigned, then the costs were determined to be non-incremental to Boston Gas. Since the costs were allocated to Boston Gas through the SEC allocation methodologies, no adjustment was necessary for ratemaking purposes.

During the course of hearings, the Company determined that the Category 2 incremental costs were not adjusted in the cost of service. These costs are identified in Exhibit AG-11-1, and total $425,031. The Company corrected this error in Exhibit KEDNE/PJM-2 [rev.1], presented at the first day of hearings on June 26, 2003.

The Company's proposed adjustment to include non-incremental costs in the Boston Gas cost of service is consistent with the accounting ruling issued by the Department in D.T.E. 98-27-A and D.T.E. 98-128 and is necessary to maintain the commitments contained therein.

⇨ Response to the Attorney General

The Attorney General contends that the Department should reject the Company's proposed incremental cost adjustment and reduce the cost of service by $8,696,000 (or $6,880,000 for Colonial and $1,816,000 for Essex) (Attorney General at 19). The Attorney General's reasons for this adjustment are myriad, but effectively are the following: (1) the Company is seeking to "replace" the incremental method of cost accounting approved by the Department with a new accounting model from the Service Company (Attorney General at 10); (2) the Service Company structure "undermines" the basis for the Department's merger orders in D.T.E. 98-27 and 98-128 (id. at 12); (3) the definition of "non-incremental" has changed (id.); (4) Boston Gas has not demonstrated that this new system of cost accounting maintains the status quo for Essex and Colonial customers, or that Boston Gas customers do not suffer harm (id.).

The Attorney General further claims that, in the alternative, if the Department decides to "charge" some level of non-incremental costs from Colonial and Essex, the Company has "still not established that the method used to distinguish incremental from non-incremental expenses results in a proper allocation of expenses among the three companies (id. at 13). In an attempt to show that the Company's method of allocation is faulty, the Attorney General goes on at length that, based on Mr. Effron's analysis, administrative and general ("A&G") expense has "increased" from the average in the period 1996-1998 to 2002, from which "the Department should conclude that the Company did not achieve any measurable efficiencies or economies of scale as a result of the Colonial and Essex mergers (id. at 17). Then the Attorney General states that, "even if the Company could hypothetically demonstrate that the Essex and Colonial acquisitions did result in economies of scale," this would not cure the basis "defect" that the Company's method of calculating the incremental cost adjustment assigns incremental costs, as well as non-incremental costs to Boston Gas, although the Attorney General does not provide any detail on how he has arrived at this conclusion (id. at 18). Lastly, the Attorney General simply concludes that, finance, human resources, legal, purchasing and property management costs are "likely" to be greater as a result of the integration, and therefore, there would be incremental expenses associated with Essex and Colonial (id.). None of these arguments hold up under scrutiny and all of these arguments represent nothing more than an attempt by the Attorney General to relitigate the Department's decision in the merger cases on this issue.

With respect to the first group of claims, i.e., that there has been a fundamental change in circumstances effectively warranting a change in the Department's decisions on the mergers, the Attorney General is just wrong. The existence of the Service Company, with its comprehensive cost-allocation procedures, presents the Department with the exact type of vehicle that the Department sought to establish when it initially ordered the joint petitioners to develop and file a cost-allocation methodology that would "functionalize all costs, classify the expenses in each functional category, identify the appropriate allocators, and allocate all costs." D.T.E. 98-27, at 47. Within that framework, there has been no change in the definition of "non-incremental" or "incremental." Most, if not all, of the functions being performed by Boston Gas prior to the arrival of the Service Company are still being provided by Boston Gas, because the Service Company structure is really more of a financial construct that allows for the tracking and allocation of costs than it is a change in the way that Boston Gas operates. See e.g., Tr. 3, at 376-377. The Service Company allocations only make explicit the cost relationships between corporate and administrative services and the operating companies, which is a true benefit in terms of the Department's investigation into the identification of incremental costs. However, the Department's policy decisions to recognize Eastern's opportunity to recoup merger costs over the 10-year period of the Colonial and Essex rate freezes dictate that the incremental cost approach must be maintained. See, D.T.E. 98-

27-A, at 5. The Company strongly believes that the Service Company structure serves to strengthen the Department's ability to make determinations regarding its incremental cost accounting orders, rather than representing such a change in circumstances that the Department would change its decisions on merger commitments.

With respect to the second group of claims, the Attorney General states that "unless the Company can demonstrate that the increase in A&G expenses since the period before the merger is due to factors other than the way expenses are allocated among the affiliates, the Incremental Cost adjustment should be reversed" (Attorney General at 15, citing Exh. AG-42, at 12) (emphasis added). The Attorney General then states that "expanding the [A&G] comparison to all O&M expenses neutralizes any effect that accounting changes have on costs charged to individual O&M expense accounts (Attorney General at 16) (emphasis added). The Attorney General then acknowledges that the Company presented a "comprehensive comparison of O&M expense," showing that O&M expense increased by 19 percent from 1996-1998 (id. at 17). Although the Attorney General disparages this analysis, in fact, the Company's analysis of all non-gas operations and maintenance expense accounts comparing the average O&M expense over the three-year period 1996-1998 with the total O&M for 2002, without any consideration for inflation, shows that if pension costs, total sales expense and system-maintenance expense are eliminated, there is only a variation of 4 percent in the 2002 expense levels, as compared to the Attorney General's 15 percent (RR-AG-101).[32]

[32] Contrary to the Attorney General's assertions, the Company's analysis does not suffer from the same defects as the Attorney General, because the Company has accurately accounted for the changes in DTE Account totals as a result of the Service Company charges. Neither of the analyses offered by the Attorney General sufficiently account for this factor.

The Attorney General attempts to argue that this analysis shows a "growth of expenses that further confirms that absence of any cost savings as a result of the acquisition of Essex and Colonial" (Attorney General at 17). As an initial matter, there is no basis for the claim that the Company somehow has a burden to show savings as a result of the Essex and Colonial mergers. Under the construct approved by the Department, all of the savings attributable to Essex and Colonial reside with those companies.

In addition, the Company's analysis does not show a "growth of expenses" relating to the mergers. To the contrary – what the Company's analysis does show is that the Company has met the Attorney General's own stated standard, which is that the incremental cost adjustment should not be allowed, "<u>unless the Company can demonstrate that the increase in A&G expenses since the period before the merger is due to factors other than the way expenses are allocated among the affiliates. . .</u>" (Attorney General at 15, <u>citing</u> Exh. AG-42, at 12) (emphasis added). The analysis presented by the Company in RR-AG-101 demonstrates precisely that, which is, to the extent that significant cost changes have occurred between 1996-1998 and 2002, those changes are <u>not</u> related to the corporate and administrative functions that Boston Gas (through the Service Company) performs for Colonial and Essex.

The record shows that the Company has performed a line-by-line analysis of the charges that belong to Colonial and Essex as a result of the Service Company structure and of the activities to which those charges relate. Exh. AG-11-1; AG-1-28. The record further shows that the Company has applied a fair and reasonable criteria by which to evaluate cost entries and has methodically applied that strategy. The Company has no burden to demonstrate "cost savings resulting from the Essex and Colonial mergers" in this case and it is simply not enough to just state the conclusion that, finance, human resources, legal, purchasing and property management costs are "likely" to be greater as a result of the integration, and therefore, there would be incremental expenses associated with Essex and Colonial, as the Attorney General has stated repeatedly. Accordingly, the Department should allow the Company's incremental cost adjustment.

(ii) The Company's Treatment of the Investment Tax Credit is Accurate and Should be Maintained in the Cost of Service.

In its initial filing, the Company deducted from rate base the test-year end balance of unamortized investment tax credits ("ITC") of $1,713,838 as reported on page 33 of the Company's annual return to the Department. Exh. KEDNE/PJM-2, at 38 of 41, line 14, Exh. KEDNE/PJM-2, Schedule 4, AG 1-2B(8)(a) at 33, line14. The Company's annual return as well as prior and subsequent annual returns clearly indicate that this unamortized ITC balance is related to post 1970 ITC. Inadvertently, the Company erroneously mislabeled the unamortized ITC balance in Mr. McClellan's schedules as being related to the pre-1971 period.

For ratemaking purposes, IRS regulations allow the annual amortization of pre-1971 ITC as a deduction to income tax expense as well as allowing the unamortized balance of pre-1971 ITC to be deducted from rate base. Section 46(f)(2) of the Internal Revenue Service Code, however, specifies that with regard to post-1971 ITC, normalization accounting is required for ratemaking purposes, and a Company has the option to select whether it desires to deduct the unamortized balance of post-1971 ITC from rate base (Option 1) or in the alternative whether it prefers to use the annual amortization of ITC as a deduction to income taxes (Option 2). Tr. 19, at 2620 -2622.

The Internal Revenue Code specifically requires that only one of these options is available for ratemaking purposes and precludes the simultaneous application of both alternatives. Violation of these requirements could result in the Company being ineligible for the ITC. The Internal Revenue Code also specifically provides that in the event a Company fails to affirmatively adopt the Option 2 approach it will be considered an Option 1 Company and the unamortized balance of post-1971 ITC will be deducted from rate base without any reduction to income taxes of the annual amortization of ITC.

Mr. McClellan testified that he had conducted a search of the Company's files and was unable to locate any documentation that would indicate that the Company had affirmatively designated itself as an Option 2 company, and therefore, since companies that do not affirmatively designate an option default to Option 1, Mr. McClellan applied the Option 1 treatment for ITC in his schedules. Tr. 25, at 3512-3513. Accordingly, the Company in its cost of service filing deducted the balance of $1,713,838 in unamortized post-1971 ITC from rate base and did not reduce its income tax calculation for the annual amortization of the ITC.

In his pre-filed direct testimony, the Attorney General's witness, Mr. Effron, based on the belief that the Company's ITC reduction from rate base was related to pre-1971 ITC recommended that the Department also adjust the income tax calculation by deducting the annual amortization amount of ITC in the test year of $842,004. During the hearings on this matter, however, Mr. Effron agreed that if the Company's ITC was in fact related to the post-1971 period it would not be permissible under the Internal Revenue Service Code to make both adjustments. Tr. 19, at 2623, Tr. 20, at 2366-2367. Nevertheless, on brief, the Attorney General asserts that based on treatment applied to

ITC in prior Company rate cases, it continues to be appropriate to incorporate the annual amortization of the Company's ITC as a reduction to income taxes. (Attorney General at 39).

Based on the testimony of Mr. McClellan, the Company believes that it is an Option 1 company and accordingly it has properly given effect to ITC in its initial filing by reducing rate base by the test-year end unamortized ITC balance. Nevertheless, if the Department were to agree with the Attorney General's position on this issue and deduct the test year ITC amortization amount of $842,004 from the Company's calculation of income taxes, it would be necessary as required by the Internal Revenue Service Code to reverse the ITC treatment contained in the Company's initial filing by eliminating the reduction of the test-year end balance of ITC from rate base, and thus, increasing rate base by $1,713,838.

(ii) The Pension Expense Included in the Company's Cost of Service is Calculated Consistent with Department Precedent and Is Appropriate for Inclusion in Rates.

The Department has emphasized that it does not endorse any specific method for the calculation of pension expense for ratemaking purposes and that the intricacies of this issue warrant an investigation on a case-by-case basis. See e.g., D.P.U. 96-50, at 81. Generally, the Company has found that basing the pension allowance on tax deductible contributions provides a reasonable basis for the determination of pension expense for ratemaking purposes. Id. In this case, the Company is proposing to establish base rates that include $18,085,435 for pension costs, reflecting the average of the Company's actual cash contributions for the three-year period 2000 through 2002 (Exh.

KEDNE/JFB-1, at 39).[33]. The Company did not make a cash contribution to its pension fund in 2000, contributed $19 million in 2001 and $44,460,083 in 2002 (Exh. KEDNE/JFB-1, at 39). The average annual cash contribution amount is $21,153,361, of which $18,085,435 would be included in base rates representing the non-capitalized portion of the expense ($17,180,551 for direct employees and $904,884 for Service Company employees) (id.).

⇒ Response to the Attorney General on Base Rate Pension Expense Level

The Attorney General claims that the Department should use the pension expense of $10,851,000 (excluding capitalized portion) that was calculated by Mr. Effron to set rates in this case (Attorney General at 42-43). Mr. Effron's calculation is based on a five-year, rather than three-year average of the actual cash contributions for the period 1998 through 2002. Stating that the Company's use of the three-year average represents an "excessive" estimation of pension costs, the Attorney General includes three years for which the Company made no cash contribution to its pension fund (1998, 1999 and 2000) in calculating the average (Exh. AG-42, at 16-17). The Attorney General argues that this is the appropriate amount for inclusion in rates because: (1) using five years rather than three years would "mitigate the effect of catch-up contributions in 2001 and 2002 (Attorney General at 42); and (2) a five-year average was used by the Department in D.P.U. 96-50, and (3) the five-year average "approximates the estimated periodic pension

[33] The Company is also proposing to establish a reconciliation mechanism to recover pension and post-retirement benefits other than pensions outside of the base-rate framework to address disconnects between ratemaking practice, accounting requirements and tax policy. This proposal is addressed below.

cost for 2003 pursuant to SFAS 87, as [Mr. Effron] has calculated it" (emphasis added) (Attorney General at 42). However, as discussed below, the record shows that Attorney General's claims regarding "catch-up" payments and the "approximation" of SFAS 87 pension costs are inaccurate. Moreover, the Attorney General's recommendation to include approximately $10 million in rates (without the establishment of a pension-reconciliation adjustment mechanism) will not constitute a "representative" level of the pension expense that the Company will incur over the term of the PBR Plan, and therefore, is not a reasonable level upon which to set base rates in this proceeding.

First, with respect to Mr. Effron's testimony "the contributions in 2001 and 2002 included a catch up for the zero funding in the earlier years," is not supported by the record. Exh. AG-42, at 14. There is no evidence in the record that the contributions were catch up payments, and as the Department has recognized in the past, the reason that a company does not make contributions in a given year is because of the funded status of the pension plan. D.P.U. 96-50, at 81 (stating "because of the well-funded nature of the pension plan, no contribution will be allowed"). In fact, the Company's minimum and maximum tax deductible contribution amounts in any given year are a function of the funded status of the pension plans, yet Mr. Effron indicated that he had not analyzed, nor had any knowledge of the Company's minimum and maximum tax deductible contribution levels in those years. Tr. 20 at 2668.

Second, there is no basis for the Department to accept Mr. Effron's calculation of SFAS 87 expense. Mr. Effron testified on the record that, in fact, he "backed into the semiannual compounding." Tr. 20 at 2665. The record shows that the Company's 2003 pension expense will be $17,366,106, as determined by its actuarial analysis. Exh. AG-

11-13; Exh. KEDNE/JFB-1, at 35. In addition, Mr. Effron could not support the use of a 6.86 percent discount rate to calculate pension expense and no record evidence supports the use of this amount. RR-AG-83. The SFAS expense calculated by Mr. Effron is, in fact, a meaningless number, since he has simply manipulated the assumptions used in determining SFAS 87 expense to arrive at a number that was comparable to the five-year average of cash contributions.

The Company's recent cash contributions to its pension fund ($44.5 million in 2002, $19 million in 2001 and $0 in 2000) are more representative of the Company's contributions than an average of the past five years because of the fundamental change in the returns previously earned by the plan in the markets. In is undisputed that the Company's cash contributions have increased more recently to address the overall decline in the plan's assets and funded status. This decline, which is not unique to the Company, reflects the experience of the U.S. economy over three consecutive years of declining equity-markets and falling interest rates (Exh. AG-11-13). In earlier years when equity market returns were high, the assets of the Company's plan required no additional contribution because the plan was fully funded according to ERISA rules. To use a five-year average, which includes three years when no contributions were required because the plan was fully funded, would represent a pension allowance that is well below more recent and anticipated trends in the market.

To the extent that the Department does not approve the Company's proposal to establish a pension cost reconciliation mechanism, it will be vitally important for the Department to set rates based on a representative amount of the cost that the Company will experience going forward for pension expense. The record does not support the

Attorney General's claim that including $10 million in rates will be representative of an expense that, in 2003, is demonstrated on the record to be approximately $17 million. Accordingly, the Attorney General's claims regarding the post-test year adjustment for pension expense must be rejected by the Department.

(iii) The Lease Expense for the Waltham Facility Meets the Department's Standard for Inclusion in Rates.

A Company's lease expense represents an allowable cost qualified for inclusion in its overall cost of service. Nantucket Electric Company, D.P.U. 88-161/168, at 123-125 (1989). Therefore, increases in office rent based on executed lease agreements are recognized in the cost of service, as are related operating expenses. Boston Gas Company, D.P.U. 88-67, at 95-97 (1988). In this case, the Company is proposing to adjust the test-year cost of service by $1,041,262 to account for the Company's new office lease, as well as a number of other adjustments. The record shows that the adjustment for property leases is necessary in order to annualize the effect of cost changes that occurred during the test year and to recognize the changes in specific properties being leased by the Company (Exh. KEDNE/PJM-1, at 17; Exh. KEDNE/PJM-2, at 14.

Specifically, the Company has annualized the increase in the lease expenses associated with the liquefied natural gas ("LNG") tanks in Lynn and Salem, Massachusetts, which became effective on July 1, 2002 (Exh. KEDNE/PJM-1, at 17). This specific adjustment results in an increase to the cost of service of $205,456 (id.). Second, during 2002, the Company terminated its lease at One Beacon Street, Boston and Morse Street, Norwood, and relocated employees from these and other locations, to consolidate its offices that are now located in Waltham (id.). Therefore, the Company reduced the test-year lease expense for the Beacon Street and Norwood facilities by $502,565 and $222,248, respectively, and increased the test-year expense to reflect the portion of the annual expense of the Waltham facility that is allocated to Boston Gas (i.e., $1,560,619). On June 25, 2003, the Company presented an adjustment to the cost of service to account for $801,429 for maintenance expenses associated with the Waltham office. Tr. at 1, at 9. The record shows that the total expenses associated with the Waltham lease are allocated among all of the Massachusetts companies with the allocation to Boston Gas being the same as previously used for the Beacon Street and Morse Street, Norwood facilities.

⇒ Response to the Attorney General on Lease Expense Adjustment

The Attorney General claims that the Department should remove the "incremental increase" in property lease expense associated with the Waltham lease, or $1,637,000, because the Company has "not demonstrated that net benefits to ratepayers resulted from the move to Waltham" or has " presented no data or analysis showing that savings exceed the substantial increase" (Attorney General at 49). Although the Company always has the obligation to reduce costs to the extent possible, there is no Department precedent that requires a utility to perform a cost-benefit analysis in relation to the execution of a lease to provide for work space for company employees, nor does the Attorney General cite any standard or precedent to support his claim that the costs of the lease should be excluded from the cost of service.

On the contrary, the Company's Waltham lease demonstrates that, on cost per square foot basis, the Company's lease expenses are less expensive than under its Boston and Norwood leases. The Company is currently leasing approximately 113,000 square feet of space in its Waltham location, which was scheduled to be used fully by the Company as of August 2003. Exh. DTE-2-2; Tr. 2, at 162-163. Under the terms of the Waltham lease, during 2003, the lease cost per square foot for Waltham is $0, increasing to $17 per square foot in Lease Year 2. Exh. DTE-2-4 (page 2 of Waltham Lease). In comparison, the Company's lease expenses during the test year for its former Norwood location were approximately $14 per square foot (for approximately 20,000 square feet) and its per square foot lease costs during the test year at its former Boston location were approximately $57-$59 per square foot (for approximately 13,000 square feet). Exh. DTE-2-4(c) (page 1 of Norwood Lease); Exh. AG-4-28 (pages 2 and 3 of One Beacon Street Lease).

Collectively, the lease costs at the Company's former Norwood and Boston locations were significantly higher than the Company's Waltham lease costs on a per square-foot basis. Beginning in 1997, the Company reduced its lease space in Boston from approximately 90,000 square feet to approximately 30,000 square feet, with additional reduction in space in Boston since that time. Exh. AG-4-28 (Boston Lease Partial Lease Termination Agreement at page 13 of attachment). Because the cost of the office space in Boston was so high, the Company relocated its employees to a number of operating centers in Malden, West Roxbury, and after the mergers, to Lowell and Essex. The Company's move to Waltham has completed a process of consolidation that has been necessary since relocating from Boston. By moving to Waltham, the Company has been able to consolidate a substantial amount of its operations at its Waltham location, vastly improving the efficiency of its working environment for employees.

Accordingly, the record demonstrates that the Company's inclusion of the property leases is reasonable, appropriate and consistent with Department precedent. Therefore, the Department should reject the Attorney General's claims regarding lease expense.

(iv) There Is No Basis to Exclude the Company's Test Year Promotional Expense

The Department has found that promotional advertising costs that represent a "tangible portion of the costs associated with implementing marketing and service programs (rather than general promotional advertisements designed to explain the benefits of gas)," must be included in an "analysis of the net benefits provided by the marketing and service programs." D.P.U. 92-111, at 193. Accordingly, under Department precedent, the Company is allowed to recover the costs associated with its marketing programs by demonstrating through record evidence that the programs provide net benefits to ratepayers. D.T.E. 01-56, at 67; Berkshire Gas Company, D.P.U. 92-210, at 103 (1993); Bay State Gas Company, D.P.U. 92-111, at 191-193, 201-202 (1993).

The record shows that, in the test year, the Company incurred a total of $13,667,512[34] associated with promotional sales and advertising expenses (booked to DTE Accounts 912 and 913, respectively). Of this amount, the Company booked $2,120,505 to Account 913 as advertising expense and $11,547,007 to Account 912 as promotional sales expense. See, Exh. AG-1-2B(8)(a) at pages 47, 80b. The amounts booked to these accounts include both direct and indirect expenses. Direct expenses are

[34] In its initial filing, the Company identified $641,204 associated with non-allowable corporate image advertising expenses, which were deducted from the cost of service. As a result, the Company is seeking recovery of total direct and indirect sales promotion and advertising expenses of $13,026,308 See, Exhs. MOC-1-1, MOC-1-2(a), AG-23-1, KEDNE/PJM-2 [rev.2], at page 24.

the costs the Company incurs in relation to the specific sales promotion or advertising activity it has undertaken (for example invoiced charges from advertising agencies to develop and publish specific advertisements and rebates associated with the Company's sales promotion activities.) Indirect expenses are associated with the salaries, benefits and overheads relating to various Company employees whose responsibilities include overseeing the Company's sales promotion and advertising activities.

Of the $2,120,505 of advertising expenses booked to Account 913 in the test year, $1,751,879 related to direct advertising expense and $368,626 related to Company labor and related expenses. Exh. AG-1-2B(8)(a) at page 80b; Exh. KEDNE/PJM-2 [rev.2], at page 24. Of the $11,547,007 of promotional sales expenses booked to Account 912 in the test year, $6,228,542 is associated with direct sales promotion activities and $5,318,465 is indirect expense related primarily to the administrative and general expenses incurred for payroll and office administration of the Company's entire sales force.[35] Exh. AG-1-2B(8)(a) at page 47; Exh. AG 23-1, at page 1 of 4; Exh. AG-13-19.

The $6,228,542 of direct sales promotion expenses incurred during the test year represents the cost of providing furnace and boiler rebates to new heating customers and the costs associated with operating the Company's Value Plus Installer program. To demonstrate the net benefits resulting from the Company's test year sales-promotion programs, the Company performed an internal rate of return analysis that compared the

[35] This breakdown differs from the breakdown presented in Exhibit AG-23-1, which shows direct expenses of $7,428,258 and indirect expenses of $4,118,749, because that exhibit was prepared to demonstrate cost allocation between the residential and commercial classes, rather than to detail direct versus indirect costs. The direct amount of $7,428,258 includes corporate administrative costs of $742,434, a reduction for vendor credits of $400,000, and other credits of $56,650, which must be removed from the direct sales-promotion expense category for purposes of performing a cost-benefit analysis. With these amounts removed, the total incentive program costs are $6,228,542, as shown in the IRR calculation presented in Exh, DTE-4-28.

stream of revenues that will be generated from new customer loads to the direct and indirect costs incurred by the Company to attract that new load and connect it to the system.[36] Exh. DTE-4-28. The record shows that, to develop the stream of revenues used in the analysis, the Company evaluated the projected annual revenue from new residential load of $6,541,421 over a 25-year period and projected annual revenue from new commercial and industrial load of $8,913,648 over a 15-year period. Exh. DTE 4-28(a). This stream of revenues was then compared to the costs incurred by the Company to obtain this new load, which include: (1) all direct costs associated with adding the new customer load, including direct company payroll, materials and contractor charges, which totaled $28,134,268; (2) all indirect costs associated with adding customer load, including supervision and clerical labor, materials handling, transportation, employee benefits, and engineering, which totaled $13,793,106; and (3) total promotional program costs of $6,228,542.[37] Exh. DTE-4-27; Exh. DTE-4-28. By using an IRR calculation to compare revenues to costs, the Company is able to determine both on a project-specific basis, as well as in the aggregate, whether the benefits of a new customer addition outweighs the cost associated with attracting that customer through promotional incentives and rebates and the incurrence of direct and indirect costs associated with installing mains, services and meters needed to connect the new load to the distribution system. The Company designed this calculation to be consistent with its internal methodologies for determining the cost effectiveness of its system-growth rate base

[36] The Company performed and provided internal rate of return calculations related to its growth related investments and sales promotion expenses for each year since 1996.

[37] In response to DTE-4-27, the Company erred in its calculation of direct sales promotion expense of $5,908,818. The Company's actual sales promotion direct expenses in 2002 were $6,228,542 as reported in Exh. DTE 4-28.

investments, as well as the Department's directives regarding the need to include promotional expenses in the requisite cost-benefit analysis in D.P.U. 01-56, at 67 (fn.20). D.T.E. 01-56-A; D.P.U. 96-50, at 22; D.P.U. 93-60, at 55-57. [38]

The IRR calculation is the most appropriate tool for evaluating the costs and benefits of promotional sales incentive and marketing program expenditures because it incorporates all direct, indirect and incentive program costs associated with the addition of new customers in the calculation of the IRR. As a result, the IRR calculation presents a conservative analysis because, when the Company adds new customers (whether low-use upgrades or new conversions from oil), the Company's fixed costs do not increase (i.e., the cost of the billing systems, call center and other such costs). However, the Company's internal rate of return calculation includes all direct and indirect costs of adding the new customer to the system so that a more conservative view is presented. The analysis calculated by the Company demonstrates that, by including all three of these cost categories, the Company's system-growth expenditures (including both rate base

[38] The annual aggregate IRRs contained in Exhibit DTE 4-28 were developed using an Excel spreadsheet and the analysis is easily duplicated. For example, the aggregate annual residential margins ($6,541,421) and commercial and industrial margin ($8,913,648) are input for combined revenue of $15,455,069 over 15 years and annual margins of $6,541,421 for an additional 10 years. Exh. DTE-4-28(a). This revenue stream is then compared to costs, including total direct and promotional costs of $48,155,916 that are incurred at the outset of the first year. Id. Following that investment, annual costs consist of an annual depreciation cost of $2,407,796 (representing 5 percent annual depreciation on the total investment of $48,155,916 over twenty years) and annual property taxes of $1,300,210 (developed by multiplying the aggregate investment of $48,155,916 by the composite property tax rate for Boston Gas of 2.7 percent for each of the 25 years). This comparison results in a net profit of $11,747,063 during the first 15 years, $2,833,415 for years 16 through 20, and $5,241,211 for years 21 through 25. State and federal taxes are then calculated for these annual net profits based on a 6.5 percent Massachusetts state tax rate and a 35 percent tax rate on the annual net profit amount less the state tax amount. The reduction of the annual net profit amounts by state and federal taxes provides the net income amount on which the IRR is calculated. The annual net income for years 1 through 15 is $9,547,074, for years 16 through 20 is $4,129,084 and for years 21 through 25 is $3,185,346. The excel IRR function is then applied to these annual net income amounts to derive the IRR of 18.83 percent and the NPV function with a discount rate of 9.5 percent is applied to the same net income numbers to arrive at an NPV of $32,636,294. This is the same methodology used to develop individual project IRR calculations. See, e.g., Exh. RR-AG-26.

additions and related program costs) produced an IRR of 18.8 percent in 2002 for growth-related investments and promotional costs, which is well in excess of the Company's weighted cost of capital as determined in D.P.U. 96-50 of 9.38 percent, and also is well above the Company's own threshold for the internal use of capital funds (or 11.75 for residential load and 12.75 percent for commercial and industrial load). Exh. DTE-4-28.[39]

The IRR calculation demonstrates that the Company's existing body of ratepayers receive a direct benefit from the Company's sales promotion activities and growth-related investments (which include direct capital costs as well as indirect embedded costs) if the program produces in an IRR that is greater than the Company's cost of capital. The exact amount by which this benefit exceeds the cost of attracting and connecting this new customer load to the Company's distribution system is measured by the amount that the net present value of the net income number exceeds the Company's cost of capital. The net present value of the Company's investment over the period 1997 through 2002 is as follows:

Year	**Net Present Value Benefit to Customers**
2002	$32,636,294
2001	$29,788,334
2000	$21,598,896
1999	$31,299,671
1998	$21,293,245

39 Similar IRR calculations were provided for previous years indicating an IRR of 18.93 percent for 2001, 17.95 percent for 2000, 28 percent for 1999, 21.34 percent for 1998 and 24.70 percent for 1997. Exh. DTE-4-28. Accordingly, the Company's aggregate growth-related investments and full annual sales promotion costs since the Company's last rate case have provided a significant benefit to all of the Company's other customers by offsetting costs previously borne by those customers in an amount equal to that amount that the IRR exceeds the Company's cost of capital of 9.38 percent, which in the test year had a net present value of $32,636,294..

Exh. DTE 4-28. Accordingly, the Company's customers are receiving a net present value benefit of an increased revenue stream over and above the Company's direct, indirect, promotional costs and cost of capital of more than $155 million as a result of the Company's growth-related investments and sales promotion activities since the Company's last rate case in 1996.

⇒ Response to Attorney General on Promotional Sales Expense

The Attorney General claims that the Department should exclude at least $11,547,007 from the cost of service for sales promotional expense because the Company failed to perform an adequate cost-benefit analysis (Attorney General at 50). The Attorney General contends that the Company's showing is inadequate because (1) the combined capital investment/promotion analysis "hid the true effectiveness" of the sales promotion programs; (2) the Company did not include all sales promotion costs in its IRR calculation; (3) the Company did not analyze the cost of adding customers on the system; and (4) the Company failed to remove sales promotion costs associated with conversions from electricity to oil (id. at 50). Lastly, the Attorney General claims that the Company's "combined economic analysis" fails to provide the Department with the "per capita cost effectiveness comparison of promotional expenses alone that the Department mandated" in D.T.E. 01-56-A at 65-66 (id. at 51). As described below, however, the Attorney General's claims misrepresent the record and the Department's precedent and also demonstrate a lack of understanding of the Company's cost/benefit IRR analysis. Accordingly, the Attorney General's recommendations regarding the Company's sales promotion expenses should be rejected by the Department.

First the Attorney General disputes the Company's "combined economic analysis," referring to the Company's IRR and NPV calculations. This IRR analysis is entirely appropriate in terms of demonstrating the benefits to customers of the Company's promotional expenditures. Moreover, the Department has never "mandated" a "per capita cost effectiveness comparison" (Attorney General at 51). In fact, the Department's criticisms of the Berkshire approach focused on the fact that the costs of installing a service and a meter to hookup a new customer were not included in the Company's analysis. The only way to ensure that all of the direct, indirect and program costs, including the cost of the new service and meter are accounted for, is to undertake an IRR calculation that takes into consideration the net present value of the flows of revenues and costs over the life of the installed measures (25 years for residential and 15 years for commercial).

In addition, when the margins associated with new customer accounts exceed the marginal cost of hooking up the customer, all customers benefit from the fact that there are additional volumes over which the Company's fixed costs will be spread in setting rates. Therefore, to evaluate whether there are "net benefits" to customers, the Company must perform an analysis that looks at all of the growth in margin versus all of the spending needed to achieve that growth. The Department has never dictated the form that the "cost-benefit analysis" must take, but rather has only dictated the components that must be considered in the calculation. The Company has included all of the components identified by the Department, and has demonstrated net benefits to customers using an internal rate of return calculation.

Moreover, the Department's directive to include all costs associated with hooking up new customers, including the marginal customer cost of installing a new meter and service means that the Company's net benefit analysis must necessarily include the cost of growth-producing investments, since those are the marginal costs that are incurred in adding customers to the system. These costs are linked – the promotional program costs are a component of the cost to add new revenue-producing load, and therefore, should be included in the calculation of the rate of return on revenue-producing projects (from an overall perspective), and conversely, the cost of the promotional programs can only be justified based on margins that are produced through the rate-base investment (from an overall perspective). Therefore, the Attorney General's claims are unfounded.

Second, the Company included total promotional costs of $6,228,000 in its calculation of the IRR because the difference between the total promotional costs of $11,547,000 recorded in DTE Account 912, and the costs in included in the IRR of $6,228,000 are payroll and other overheads costs associated with the Company's sales force, administrative support and other accounting adjustments that do not represent costs associated with adding a new customer within the IRR calculation. Contrary to the Attorney General's claims, there is no Department precedent to support the inclusion of sales-force overhead expenses in the IRR calculation, nor has the Attorney General cited any precedent. In fact, the Department has never required <u>any</u> utility company to include sales-force overhead costs in a calculation of IRR. Those costs are fixed costs of the Company's operations that would not be reduced or eliminated if the Company were to terminate its marketing and incentive programs, whereas the direct and indirect costs of actually adding customers to the system, are a function of customer additions, and therefore, are the items that the Department has generally required companies to include in the calculation of the IRR. As a result, there is no basis to include the Company's total promotional expense in the calculation.

Third, the Attorney General claims that the Company did not analyze the "cost of adding customers on the system" (Attorney General at 50). This is not true. The Company's marginal cost study sets forth a detailed analysis of the marginal costs associated with hooking up a new customer and these costs are used in the IRR calculation. As Exhibit DTE 4-28(a) clearly demonstrates, the Company has incorporated in its cost/benefit IRR analysis \$48,155,916 of investment, of which \$6,228,542 relates to the Company's promotional sales and incentive programs and \$41,927,374 relates to the cost of adding customers to the system. The record shows that, of this amount, \$41,082,384 relates to the direct and indirect costs incurred to install total mains and services and \$844,990 relates to the procurement and installation of meters. Exh. DTE 4-28(a). The backup and underlying basis for these costs is fully detailed in the marginal cost study presented in Exhibit KEDNE/ALS-2. The electronic version of this exhibit was also provided to the Attorney General and contains all of the assumptions and calculations underlying the direct and indirect cost figures contained in Exhibit DTE 4-28(a).

For example, the direct costs for the installation of mains is listed by the size of the main installed in the electronic spreadsheet version of Exhibit KEDNE/ALS-2.XLS tab "footage" lines 34 - 48. These direct costs total to \$10,423,396. After applying the General Plant Loader of 6.5 percent and the Administrative and General Loader of 0.67 percent, the Company's direct and indirect costs associated with main installations totals

$11,170,754 (i.e., $10,423,396 * 1.0717 = $11,170,754). Exh. KEDNE ALS-2.XLS tab "sch8" lines 14, 18.

Similarly, the direct costs associated with service installations are derived from the marginal cost study. In this instance, the Company applied the marginal cost of a new service installation of approximately $1500 for residential customers and $17,656 for C&I customers. Exh. KEDNE ALS-2.XLS tab "sch2" column E, line 23. The Company then applied the General Plant Loader of 6.5 percent and the Administrative and General Loader of 0.67 percent from Exhibit KEDNE ALS-2.XLS tab "sch9" column E, lines 12, 26 to arrive at a marginal direct and indirect service installation cost of $1608 for residential customers and $18,921 for commercial and industrial customers. Accordingly, the Attorney General's claim regarding the failure to analyze the cost of adding customers must be rejected.

Lastly, the Attorney General claims that the Company failed to remove sales promotion costs associated with conversions from electricity to oil (id. at 50). However, none of the Company's sales promotion programs are available to customers converting from electric service. The central objective of the promotional programs is to convert customers who are low-use (i..e., currently non-heating customers) or located on the Company's mains, but currently taking oil service rather than gas service (i.e., new gas conversion customers). Therefore, although the record shows that approximately 1,034 customers converted from electric to gas service in the test year, none of these customers were eligible for offers under the Company's promotional programs.

⇨ Response to MOC on Promotional Sales Expense

In its initial brief, MOC makes three claims regarding the Company's promotional sales expense, which are for the Department to disallow rate recovery of: (1) promotional programs that encourage customers to convert to a fuel that is "forecast to be extremely high as compared with historic levels" (MOC at 7); (2) all costs associated with the free equipment program (MOC at 14); (3) all costs associated with the Value Plus Installer Program ("VPI") (MOC at 18; and (4) all advertising expenses (MOC at 28). None of these claims should be accepted by the Department.

First, nowhere in the Department's standard for recovery of promotional expenses is there a requirement for the Company to demonstrate that the price of its product compares favorably to historical prices or even prices for other fuels. In fact, a decision by the Department to bar the Company from including costs associated with promoting its product would (1) cause harm to customers, who benefit from added load on the system that provides a net return; and (2) harm the Company's competitive position vis-à-vis other fuel sources with which it competes (e.g., heating oil). Accordingly, this claim must be rejected by the Department.

Second, all of the costs of the VPI program are combined with promotional marketing expenses in DTE Account 912, and were factored into the IRR calculation provided in Exhibit DTE-4-28. With respect to those expenses and the calculation of a "net benefit" to customers, MOC mischaracterizes the Department's standard in terms of the recovery of promotional expenses in order to justify its claims that these expenses should be excluded from the cost of service. Specifically, MOC claims that there is a two-part standard for the recovery of promotional expenses, which is that (1) the

Company must meet "a threshold burden that the particular program provides a true direct benefit to the ratepayer;" and (2) the Company must demonstrate through a "clear cost/benefit analysis that there is an economic benefit to the ratepayer" (MOC at 15). MOC claims that under the first part of the standard, the term "direct" means that the program must provide an "immediate advantage and value to the ratepayer and that the ratepayer will experience first-hand personal gains," and that the Company has not met this standard because the goal of the Company's program is to secure additional customer load rather than providing customers with a "personal benefit" (id.). MOC further claims that the second prong of the standard requires the Company to perform a cost-benefit analysis as discussed in D.T.E. 01-56, and that the Company has not met this standard because it "performed its own calculations" (MOC at 16). MOC is neither correct in terms of the Department's standard or in terms of the Company's satisfaction of the Department's standard.

The Department has never articulated a two-part standard that requires a company to demonstrate "personal benefits" for customers. The only standard ever established by the Department for recovery of promotional expenses is that a company must demonstrate that its marketing programs provide net benefits to ratepayers. D.T.E. 01-56, at 67; Berkshire Gas Company, D.P.U. 92-210, at 103 (1993); Bay State Gas Company, D.P.U. 92-111, at 191-193, 201-202 (1993). In D.T.E. 01-56, the Department found that the Company failed to include marginal customer costs in its net-benefit analysis. The Department did not establish any new standard or requirement for an analysis in that case, nor has the Department prescribed the manner in which net benefits to customers must be demonstrated. The Berkshire case stands only for the proposition that all costs associated with the programs, including the marginal cost of hooking up a newly converted gas customer, must be included in the analysis. In fact, in all cases where the Department has reviewed this issue, it is clear that the "benefits" that the Department seeks to have companies demonstrate is that there is a positive net return of margin to the system with the addition of new customers, after accounting for the direct, indirect and promotional program costs associated with adding those new customers.

In term of the effect of added load, or new net margin, the benefit to customers is clear and direct. Over time, the investment made by customers through the support of promotional advertising and marketing expenses, is rewarded with rates that are lower than they would otherwise be because there are more volumes over which the Company's fixed costs are spread. See e.g., D.P.U. 96-50, at 22 (stating, "[t]he Department has stated that existing customers receive benefits whenever, all other things equal, the rate of return on the incremental rate base exceeds the utility's overall required rate of return").

As stated above in relation to the Attorney General's arguments in relation to a demonstration that the Company's promotional expenses provide a net benefit, it cannot be overlooked that the Department has directed companies to include all costs associated with hooking up new customers, including the marginal customer cost of installing a new meter and service. As a result, the promotional program costs are linked to the cost of adding new revenue-producing load, and therefore, should be included in the calculation of the rate of return on revenue-producing projects and vice versa. Therefore, as with the Attorney General's claims, MOC's claim that it was inappropriate to group the promotional program costs with the "revenue-producing" investments is misguided.

⇨ The Department Should Reject MOC's Claims Regarding the Payback Analysis and Restrictions on the Use of the KeySpan Logo

MOC claims that the Department should direct the Company to provide conversion customers with a "payback analysis" prior to making a conversion decision (MOC at 31). MOC has posed this request to the Department in prior cases, along with various claims regarding anti-competitive practices, anti-trust violations abuse of monopoly market power and similar arguments. Moreover, the record shows that the Company does not have information on all of the costs involved in the conversion (because the Company does not install the equipment or get involved in other aspects of the conversion), and in addition, a payback analysis requires conjecture on the price of gas, which is not under the control of the Company. The Department has ruled that these matters are better addressed in other legal forums. Massachusetts OilHeat Council, Inc, D.T.E. 00-57, at 9-10, fn.6 (2001). MOC has not presented any evidence to support a change in the Department's findings on this matter.

Second, MOC requests that the Department amend 220 CMR 12.00 Standards of Conduct for Distribution Companies and Their Affiliates in order to prevent KeySpan HVAC affiliates from using KeySpan in their names (MOC at 31-37). MOC acknowledges that the Department's regulations governing affiliate conduct allow an affiliate to use an LDC's name or logo (id. at 32). However, MOC claims that the mere use of the common term "KeySpan" in both the name KeySpan Home Energy Services ("KHES") and KeySpan Energy Delivery gives the appearance to the public that the utility is speaking on behalf of KHES (id. at 33). MOC further claims that this creates confusion for consumers regarding the Company and its non-regulated affiliates is the basis of MOC's requested relief (id. at 36-37).

MOC provides three examples to support its concern that there is unacceptable public confusion between the Company and KHES. First, MOC addresses the fact that the Company and KHES both have web pages in the KeySpan corporate web site and that there are links that allow users to transfer from one company's web page to the other company's web page (id. at 34-35). Second, MOC describes a KHES ad in the Boston Herald promoting gas conversions by KHES that also refers to the Company's free equipment program (id. at 35-36). Third, MOC mentions that KHES received $17,000 in advertising "subsidies" from the Company (id. at 36). None of these examples support MOC's claims of an unacceptable blurring of the public perception of KHES and the Company, let alone provide a basis for the extraordinary relief MOC seeks, which is to change the Department's affiliate rules solely as they apply to KeySpan.

In addition, MOC's description of the website accurately characterizes it an overall KeySpan website in which KHES and the Company maintain separate information on separate pages (id. at 34-35). The Boston Herald ad referring to the availability of a local free-equipment program would be expected from any heating contractor seeking to promote its conversion business. MOC acknowledges that the ad contains a disclaimer that "purchase from [KeySpan Home Energy Services] has no effect on the availability, price or terms from KeySpan Energy Delivery." MOC also mentions that the ad states that the Company offer may not be combined with any other KHES offer. This as well as the disclaimer would seem to make it quite evident that KHES and the Company are two different entities (id. at 35-36). Moreover, the $17,000 subsidy is provided through the Company's cooperative advertising program that it makes available to any heating contractor. RR-MOC-5. Not only does the ad comply with the Department's standards of conduct (which are aimed at minimizing customer confusion), similar ads have been placed by competitors of KHES through the Company's trade ally program (see e.g., Exh. AG-25-1).

The Department fully addressed MOC's concerns in Standards of Conduct, D.P.U/D.T.E 97-96 (1998) establishing standards of conduct governing the relationship between electric distribution companies and their affiliates and between natural gas local distribution companies and their affiliates. In that order, the Department concludes that any restrictions on the use of a distribution company's corporate name and logo should be drafted narrowly. There are several reasons for this conclusion. First, the corporate name and logo belong to shareholders, not ratepayers and, excessive restrictions of their use could violate a company's First, Fifth, and Fourteenth Amendment rights. Id. (citations omitted). Second, the corporate name and logo provide information that customers seek and value—namely, the affiliations of the companies from which they are considering buying products and services" (id. at 23). The Department goes on to explain that any customer confusion that may occur can be prevented by the use of a disclaimer, as MOC acknowledges KHES has done (id. at 24).

MOC has not alleged any specific violation of the standards of conduct by the Company (in fact it acknowledges that "the Company has attempted to draw a clear line between all its corporations" (id. at 31). Nor has MOC provided any basis for the Department to change its affiliate regulations and apply that change solely to the Company and its affiliates. Accordingly, MOC's claims should not be accepted by the Department.

(v) The Company's Advertising Expenses are Not "Miscategorized" and Are Appropriate for Recovery Through Rates

The Department's policy on the recovery of promotional expenses has evolved over time and stems from the provisions of G.L. c. 164, § 33A, which state that:

> No gas or electric company may recover from its ratepayers any direct or indirect expenditures for promotional or political advertising, except where such advertising informs consumers of an stimulates the use of products or services which are subject to direct competition from products or services of entities not regulated by the Department.

To avoid the ban on promotional advertising under G.L. c. 164, § 33A, a company must show that its advertising qualifies for one of the stated exemptions, e.g., that it competes with fuel oil. Bay State Gas Company, D.P.U. 92-111, at 192 (1993); Boston Gas Company, D.P.U. 88-67, at 112 (1988). Therefore, under Department precedent, general promotional advertising aimed at a non-regulated energy source (e.g., oil), or that leaves the reader/listener with the impression that a non-regulated energy source is the target of the advertisement may be recovered from ratepayers.[40] The Berkshire Gas Company, D.P.U. 90-121, at 133 (1990); D.P.U. 92-111, at 186. If the advertisement meets this condition, it will be included in cost of service, subject to certain constraints. For example, the Department has apportioned costs between ratepayers and shareholders for multi-purpose advertisements (those directed at both regulated and non-regulated energy users). Bay State Gas Company, D.P.U. 92-111, at 187-188 (1992). The amount allocated between ratepayers and shareholders is based on the percentages of consumption associated with the end-users targeted in the ad. Id.

[40] The Department has stated that it would be an unnecessarily narrow interpretation of G.L. c. 164, § 33A to require that the company specifically name the unregulated fuel. D.P.U. 92-111, at 186.

The Company incurred advertising expenses of $1,751,879 during the test year. Of that amount, the Company deducted $641,204 from the total test-year expense for advertising costs that were related to the Company's image and promotional activities (Exh. KEDNE/PJM-1, at 28; Exh. KEDNE/PJM-5; Tr. 1 at 79). Accordingly, the Company proposes to recover $1,110,675 for costs related to specific advertisements.[41] Consistent with Department precedent, the advertising expense for which the Company seeks recovery is related to general information advertising and general promotional advertising targeted at promoting the efficient use of gas over an unregulated fuel (i.e., heating oil).

The Attorney General claims that the Department should reduce the cost of service by $670,000 to account for advertisements that do not meet the Department's standard for cost recovery. The Company will address these claims in sequence:

⇨ Value Snobs Ad

The Attorney General claims that the cost of the Value Snobs advertisement, which is $92,663, should be excluded from the cost of service because the ad did not run, and therefore, it provided no benefit to customers (Attorney General at 54). However, the invoices cited include significant charges for airtime, and since the ad did not run, those charges do not apply to the Value Snob ad. Instead, those charges apply to the Bathtub Ad, which is also covered by the same invoices. The record shows that the development costs of the Value Snob ad totaled only a small fraction of the total costs. See, e.g., RR-54-B; Exh. AG-11 ($2,717). Accordingly, no more than that amount should be excluded from rates.

41 This amount added to the total promotional sales expenses of $11,547,007, equals the total amount for advertising and promotional expense noted above of $13,026,308.

⇨ Missing or Illegible Invoices/Advertisements

The Attorney General claims that the Department should exclude invoices or the cost of advertisements totaling $48,212, based on claims that such invoices or advertisements were not provided by the Company or were illegible (Attorney General Initial Brief at 82, citing Exhs. AG-20-1 and AG-25-1). The Company does not dispute the Attorney General's claims in this regard, with the exception of four invoices. First, an invoice from JP Graphics totaling $34,075 (Invoice Locator #36) that was included in the Company's response to Information Request AG-20-1 is fully legible. Moreover, of the advertisements referenced by the Attorney General as either "missing" or "illegible," three (AG-25-1 (53), (129) and (137)) were also filed by the Company and are legible. The costs of these advertisements total approximately $5,000. The Attorney General offers no other basis for the exclusion of these invoices than they are not legible, which is not proven by the record. Accordingly, the Department should disregard the claims of the Attorney General regarding these invoices and advertisements and allow the respective costs to be included in the Company's cost of service.

⇨ Advertisements Encouraging the Use of Natural Gas

The Attorney General suggests that the Department exclude advertising costs of $230,151 because these expenses are associated with ads that encourage consumers to use natural gas rather than electric water heaters, air conditions, pool/spa heaters, stoves, fireplaces and patio lights (Attorney General Initial Brief at 54-55). In addition, the Attorney General request that the Department exclude $173,164 in expenses relating to advertisements that impart information on charitable donation, historical renovations projects, business cards and other community development (id.). The Attorney General makes this request on the claim that the Company has not demonstrated a "direct benefit" to Massachusetts consumers (id.).

However, under statute and Department precedent, utility companies are allowed to recover costs relating to promotional advertising to the extent that such advertising informs consumers of the use of products or services that are subject to direct competition from products or services of entities not regulated by the Department or any other governmental agency. G.L. c. 164, §33A; see also The Berkshire Gas Company, D.P.U. 92-210, at 98 (1993); Bay State Gas Company, D.P.U. 92-111, at 186 (1992). With respect to the Company's advertising expenses promoting the use of gas-heated fireplaces, the Company is competing directly with providers of wood and pellet stoves, neither of which are regulated. Moreover, with respect to advertising expenses promoting gas-heaters for swimming pools, the advertising is aimed at promoting customers to heat their pools, as opposed to leaving them unheated. In neither instance is the Company promoting the use of gas against a product regulated by the Department. Accordingly, the Department should allow the Company to include in its cost of service costs relating to advertising for these items.[42]

(vi) The Company's Bad Debt Expenses Are Accurately Calculated.

During the year, the Company estimated its bad-debt expense based on revenue levels and trends in the historical write-off percentages (Exh. KEDNE-PJM-1, at 27). For purposes of calculating the uncollectible-account expense to be included in the test-year cost of service, the Company first compared its net write-offs to firm billable revenue for

[42] Specifically, the Company should reject the Attorney General's arguments with respect to the following: (1) invoices: Exh. AG-20-1(6), (15), (18), (29), (35), (40), (45), (52), (56) and (60), which total $5296; and (2) advertisements: Exh. AG-25-1(20), (35), (56), (62), (65), (88) and (136), which total $7,056.

the three years ended December 31, 2002 and derived the three-year weighted average of net write-offs as a percentage of billable revenue (id.; Exh. KEDNE/PJM-2, at 22, Revision 2). The Company's net bad debt write-offs for 2002 were $15,572,000 (AG-1-34, at 9; AG-1-69; Tr. 8, at 959). The Company then took the normalized firm-sales revenues in the test year and multiplied it by the three-year weighted average to compute the bad-debt expense allowance of $11,203,982 (Exh. KENDE-PJM-1, at 27; Exh. KEDNE/PJM-2, at 22, Revision 2; Tr. 8, at 959, 961). The test year bad-debt expense of $15,503,342 was subtracted from the bad-debt expense allowance, which results in a reduction to test-year O&M expense of $4,299,361 (Exh. KENDE-PJM-1, at 27; Exh. KEDNE/PJM-2 [rev.2], at 22; Tr. 8, at 959, 961). An additional bad-debt expense of $1,115,739 results from the proposed rate increase, as shown on the Revenue Deficiency Summary provided at Exhibit KEDNE/PJM-2, at 1.

The Attorney General contends that the Department should revise the Company's 2002 net write-offs and the total bad-debt expense adjustment, claiming that the test year amount is not representative (Attorney General at 56-57). The Attorney General bases his contention on the fact the Company failed to include accurate amounts related to recovered bad-debt expenses during the second half of 2002, which, in turn, results in an inflated three-year average of net write-offs and allowable bad debt expenses, and therefore, the Attorney General contends that the total bad-debt expense adjustment should be reduced (id. at 57).

The issue with the bad debt write-offs is that the CRIS system records gross write-offs, recoveries and net write-offs, but immediately following implementation in July 2002, the system did not have the ability to report recoveries, because the regulatory requirements in New York do not call for that type of report. Following the implementation of the system, the Company has ensured that these reports will be available going forward. The unavailability of the report on recoveries, however, does not undermine the validity of the net write-off data. The record shows that, although the Company did not record recoveries for the months of July through September 2002 because of the Company's conversion to the CRIS billing system, it has accurate records of the Company's gross and net write-offs for the entire test year.

This is shown by the record in Exhibit AG-1-34 (Boston Gas Company Chart of Accounts 1999-2002), which shows gross write-offs of $17,260,528 for 2002 and recoveries of $1,688,745 for the same period (Exh. AG-1-34, at 9, General Ledger Nos. 26003 and 26004, respectively). The net of these figures is $15,571,783. This figure is also shown in Exhibit AG-1-69 ($13,460,587 of residential net write-offs plus $2,111,196 of commercial net write-offs equals $15,571,783).

Accordingly, the Company has supported its net bad-debt expenses for the test year with record evidence, and therefore, its reduction to test year O& M expense related to bad debt should be approved by the Department.

(viii) The Company's Calculation of the Gain on the Sale of the Concord Property is Accurate

Until 1998, the Company owned a 7-acre parcel of land and a building in Concord, Massachusetts (the "Concord Property") that consisted of both utility property and property held for future use (Exh. KEDNE/PJM-1, at 17). Upon the sale of the Concord Property, the Company realized net proceeds of $1,279,700 (i.e., sale proceeds of $1,436,570, less the net book value of the building and equipment of $156,870) (id. at 18). The Company allocated 16.60 percent of the proceeds to utility operations based on the ratio of the square footage used as utility property to the total square footage, including the property held for future use (id.). Accordingly, the record demonstrates that the net gain resulting from the sale allocated to utility property is $212,430, less the book value of the land underlying the facility of $9,950 (id.; Exh. KEDNE/PJM-2, at 15). This resulted in a net gain of $202,480.

As documented on the record, the Company's proposal to amortize the amount over the five-year period of the PBR Plan in order to return the amount to customers is consistent with Department precedent regarding the gain on sales of utility property and should be approved. See Boston Gas Company, D.P.U. 1100, at 62-65 (1982); Massachusetts-American Water Company, D.P.U. 95-118, at 142-143 (1996).

(ix) The Company's Non-Union Salary and Incentive Compensation Increases are Reasonable and Meet the Department's Standard for Inclusion in the Company's Cost of Service

⇒ **Non-Union Employee Compensation**

In this proceeding, the Company adjusted its test-year payroll expense by $1,408,642 to account for non-union pay increases that will take effect through the midpoint of the rate year (April 30, 2004). (Exh. KEDNE/JCO-1, at 9; Exh. KEDNE/PJM-2, at 10-11); See Fitchburg Gas & Electric Light Company, D.T.E. 02-24/25, at 89-90 (2002); The Berkshire Gas Company, D.T.E. 01-56 at 54-55 (2002). The Company's non-union payroll adjustments are designed to: (1) annualize test-year payroll costs to reflect wage and salary increases that became effective during the test year; (2) incorporate payroll increases that became effective on April 1, 2003; and (3) incorporate payroll increases that take effect prior to the midpoint of the rate year (i.e., April 30, 2004) (Exh. KEDNE/PJM-1, at 7). The adjustments relate both to direct-charge non-union payroll and the payroll expense allocated to Boston Gas from the Service Company (id.; Exhs. KEDNE/JCO-2 through JCO-4). As described below, the Company's adjustments to test-year employee compensation are known and measurable and reasonable, and should be approved by the Department.

In order to recover an increase in non-union wages, the Company must demonstrate that: (1) there is an express commitment by management to grant the increase; (2) there is an historical correlation between union and non-union raises; and (3) the non-union increase is reasonable. Fitchburg Gas & Electric Light Company, D.T.E. 02-24/25, at 89-90 (2002); The Berkshire Gas Company, D.T.E. 01-56, at 54 (2002); Boston Gas Company, D.P.U. 96-50 (Phase I) at 42 (1996); Massachusetts Electric Company, D.P.U. 95-40, at 21 (1995). To determine the reasonableness of non-union base wages and increases, the Department considers how a company's proposed non-union base payroll and increases compares with wages paid to employees at similarly-situated companies that compete for skilled employees. See Massachusetts Electric Company; D.P.U. 92-78, at 25-26 (1992); Bay State Gas Company, D.P.U. 92-111, at 102 (1992).

As described by the Company in this case, the Company's non-union payroll structure consists of base pay and incentive pay (Exh. KEDNE/JCO-1, at 6). A non-union employee's base pay may increase over time as a result of annual merit (or "general wage") increases, which are awarded if the employee meets the performance criteria for his or her job position (Exh. KEDNE/JCO-1 at 6; Exh. KEDNE/JCO-3). A non-union employee's base pay may also be increased to account for banding adjustments, which are base-pay increases resulting from promotions, market adjustments or changes in job responsibilities (Exh. KEDNE/JCO-1, at 6).

With regard to the first prong of the standard, the record demonstrates that, on April 1, 2002, payroll increases were effective for non-union employees of Boston Gas with direct employees receiving an increase of 2.75 percent and Service Company employees receiving an increase of 3.75 percent (Exh. KEDNE/PJM-1, at 9; Exh. KEDNE/JCO-1, at 6). These increases were annualized for the test year (Exh. KEDNE/PJM-1, at 9; Exh. KEDNE/PJM-2 (Supp.)). For non-union payroll increases taking effect during 2003, the Company documented an express commitment from management that non-union merit increases will become effective October 1, 2003 (for management) and on March 1, 2004 (for officers) (Exh. KEDNE/JCO-1 at 6-7; Exh. KEDNE/JCO-3; Exh. AG-6-15). Specifically, the record shows that Boston Gas non-union employees will receive a merit increase of 2.5 percent of base salary on October 1, 2003 and New York-based employees will receive a merit increase of 3.5 percent (id.).[43] The record also shows that merit increases for corporate officers are scheduled to take effect by March 1, 2004 and will be made consistent with the Company's historical practice to grant increases to corporate officers that are equal or up to one half a percent higher than management increases (Exh. KEDNE/JCO-1, at 8).[44]

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[43] After the filing of the Company's petition on April 16, 2003, KeySpan reduced the 2003 non-union payroll increase by 1 percent to save costs (see Tr. 16, at 2051; see also Exh. KEDNE/JCO-1 [supp.], at 7).

[44] The record shows that, although the precise amount of the merit pay increase for officers scheduled for March 2004 will be approved by the Company's Board of Directors in the future, the increases will be based on KeySpan's guidelines for management merit pay increases (Tr. 16, at 2152). The Company has provided its policies for merit pay increases for non-union employees (Exh. AG-6-16; Exh. AG-6-17; Exh. AG-6-16 (a) through (g)).

The Attorney General does not contest the Company's commitment to, or calculation of, the non-union wage increases. Accordingly, the record demonstrates that the Company has met the first prong of the Department's standard by demonstrating an express commitment to grant non-union wage increases in the amount of $1,408,642.

The Company has also established the requisite historical correlation between union and non-union increases. Exhibit KEDNE/JCO-4 (revised) demonstrates the historical correlation between union and management increases for an 11-year period ending with 2003. The Company also compared the non-union and union increases for the Service Company since the merger of KeySpan and Eastern Enterprises (Exh. KEDNE/JCO-4 (revised)). This analysis shows that both the Company and the Service Company have consistently increased non-union salaries over the historical periods at levels comparable to the union increases (id.; see Tr. 16, at 2055-56). The Attorney General does not dispute that the Company's analysis of the historical correlation between union and non-union salaries and wages. Accordingly, the record demonstrates that the Company has met the second prong of the Department's standard.

With respect to the third prong of the Department's standard, the record shows that the non-union wage increase is reasonable. The record shows that, in order to attract and retain qualified employees at reasonable cost, the Company's policy is to compensate employees at the 50th percentile of the geographic region in which the employees work (Exh. KEDNE/JCO-1, at 4; Exh. DTE-2-14). To that end, the Company provided two surveys to compare salary expense levels and payroll increases for non-union employees (Exh. KEDNE/JCO-1, at 17). First, the Company submitted the results of an AGA survey that compares representative and comparable Boston Gas Company non-union base salaries and total compensation with the salaries and total compensation of: (1) Northeast local distribution companies; and (2) general industry (Exh. KEDNE/JCO-1, at 17; Exh. KEDNE/JCO-9; Exh. AG-10-8 **CONFIDENTIAL**). The exhibit demonstrates that the salaries and total compensation for Boston Gas Company management employees are comparable to those of Northeast local distribution companies and non-utility companies in the Greater Boston area (Exh. KEDNE/JCO-1, at 17; Exh. KEDNE/JCO-9; Exh. AG-10-8 **CONFIDENTIAL**). The exhibit also demonstrates that the salaries and total compensation for New York-based Service Company positions compare favorably with the total compensation of Northeast local distribution companies and non-utility companies in the New York metropolitan area (id.).

The Company also demonstrated that the Company's merit increases (on a percentage basis) for non-union employees in 2002 and 2003 are consistent with the average increases of other utility and non-utility companies for the same time periods (Exh. KEDNE/JCO-1, at 17-18; Exh. KEDNE/JCO-10; Exh. AG-10-18 **CONFIDENTIAL**; Exh. AG-10-19 **CONFIDENTIAL**). Accordingly, the Company's non-union and executive salaries, together with the adjustments based on known and measurable increases to take effect before the midpoint of the rate year, are reasonable and otherwise in accordance with Department precedent (see also Exh. DTE-2-32 (rev.)).

Over and above the Department's three-pronged standard, the Department may consider whether a company's employee compensation decisions result in a minimization of unit-labor costs. See, e.g., D.P.U. 96-50 (Phase I) at 47. Therefore, the Department requires companies to demonstrate that their total unit-labor cost is minimized in a manner that is supported by their overall business strategies. Id. In this case, the

Company demonstrated that its overall business strategy regarding total unit-labor costs is to reduce costs to the maximum extent possible without affecting the safety or reliability of service provided to customers (Exh. DTE-2-20). Mr. Orlando noted that, in order to meet that objective, each of the Company's business units is charged with the task of seeking to meet or undercut annual budgets that impose strict spending parameters upon the individual business units (id.). As a result, the Company generally does not perform unit-labor cost studies from an overall corporate level, but rather evaluates unit labor costs at the business-unit level (Tr. 16,a t 2157; Exh. DTE-2-18; Exh. DTE-2-19). For example, the record shows that the Company is currently participating in a benchmarking study that will compare the Company's customer-service expense levels per customer, including labor expense, to approximately 35 other utilities across the United States and Canada, with final study results expected in October 2003 (Exh. DTE-2-19). As another example, Mr. Orlando described how the Company's use of competitive bidding for labor-related contracts helps to meet the Company's goal (id.). Lastly, the Company provided the Department with a comprehensive analysis of the Company's cost performance, as developed by the Pacific Economics Group (Exh. DTE-2-19; Exh. KEDNE/LRK-3).

⇒ Incentive Compensation

Incentive compensation represents the variable portion of the wages and salaries paid to union and non-union employees serving the Company (Exh. KEDNE/PJM-1, at 10; Exh. AG-6-19). The Department has traditionally allowed incentive compensation expenses to be included in utilities' cost of service so long as those expenses are: (1) reasonable in amount; and (2) reasonably designed to encourage good employee performance. Fitchburg Gas & Electric Light Company, D.T.E. 02-24/25, at 99 (2002). As described below, the Company has demonstrated that its employee compensation expenses meet the Department's standard for inclusion in the Company's cost of service.

First, the Company demonstrated that its incentive compensation payments are reasonable in amount. In that regard, the Company adjusted its test-year incentive payments at the test year target level, or approximately $1.1 million (Exh. KEDNE/JCO-1, at 11; Exh. DTE-2-15). The record shows that this is less than the amount actually paid out in the test year. Exh. AG-1-35. In addition, the record shows that range of target incentive payments during the test year ranged from $750 for union employees to approximately $22,000 for non-union employees (Exh. AG-6-21). This range is consistent with the range of incentive compensation payments paid by other utility companies and approved by the Department (see, e.g., D.T.E. 02-24/25, at 100, showing a range of payments between $1,900 and $110,000). Moreover, the Company's proposal to include in rate base its test-year target level of incentive compensation is reasonable because, although such payments may be more or less than the target level over the course of the Rate Plan, the test-year target level is most representative of what the Company's incentive compensation expense will be over time (Exh. KEDNE-JCO-1, at 11). Accordingly, the Company has demonstrated that its test-year incentive compensation payments are reasonable in amount.

In addition, the Company demonstrated that its Incentive Compensation Plan is reasonably designed to encourage good employee performance. Mr. Orlando testified that the Incentive Compensation Plan is a critical tool in achieving its overriding corporate objective of building long-term value for customers, shareholders and employees (Exh. KEDNE/JCO-1, at 9).[45] Mr. Orlando described the basic structure of the Incentive Plan as involving: (1) specific performance goals that, if achieved, will be beneficial to customers and shareholders; and (2) financial incentives that are linked to various performance levels (id.; see also Exhs. AG-10-26 and AG-10-30 (supp.)).

With regard to specific performance goals, the Incentive Plan includes three categories, with employee-driven goals falling into one or more of these categories: (1) corporate goals; (2) business unit or area-specific goals; and (3) strategic initiative or assessment goals (id.). Mr. Orlando testified that, during 2002, the specific goals for Boston Gas employees included the following: (1) achieving earnings objectives; (2) containing operations and maintenance costs; (3) ensuring customer satisfaction; (4) maintaining or improving safety; and (5) developing workforce diversity (id. at 10). The performance goals for each category are weighted consistent with the priorities of the business unit within which an employee functions (id.). The performance results achieved are dependant upon each employee's efforts within the KeySpan organization (id.; see also Exh. DTE-2-16A, Tr. 16, at 2160-87).

Mr. Orlando and Mr. McClellan also described the pay-out scale for each performance goal. If performance goals or targets are met for the annual performance period, employees receive 100 percent of the target pay-out amount (id.; Exh. KEDNE/PJM-1, at 10). In addition, a minimum level, or "threshold," is established for each performance goal, as well as a "maximum." (id.). For performance at the threshold level, the incentive pay-out is 50 percent of the target-incentive level, and if performance

[45] All of the Company's employees have the opportunity to receive incentive pay, whether union or non-union (Tr. 16, at 2078).

is at or above the maximum, the pay-out is two times the target level (id.). Pay-outs are prorated to the extent that performance falls within this bandwidth (id.).

Accordingly, the Company's Incentive Compensation Plan meets the Department's standards that the expenses are: (1) reasonable in amount; and (2) reasonably designed to encourage good employee performance, and therefore, should be approved by the Department.

⇒ Response to the Attorney General on Non-Union Employee and Incentive Compensation

The Attorney General contends that the Company has failed to demonstrate that its non-union wage increases are reasonable and that the Department should disallow the post-test year adjustment because: (1) the Company's average total compensation per employee is greater than that of other New England gas company employees; and (2) the Company's comparative analysis of employee compensation contains miscalculations (Attorney General at 65). With respect to the alleged "flaws" in the Company's compensation analysis, the Attorney General claims that (1) a mislabeling mistake "renders the comparison analysis on [Exhibit KEDNE/JCO-7] useless" and "casts doubt" on the remainder of the Company's employee-compensation analysis (id. at 66); and (2) the analysis casts "an overly broad net" among the New England utility companies by including electric companies (id.). Neither of these claims have any merit.

First, the Department should reject the Attorney General's contention that the Company's data hinders the Department's ability to assess the reasonableness of the Company's proposed wage increase (Attorney General at 65-66). The "flawed" study referred to by the Attorney General was an exhibit supporting the Company's **union** wage levels and not management wage levels (see Exhibit KEDNE/JCO-7). In fact, the

Company has presented several studies to the Department comparing the Company's non-union employee compensation to that of both regulated and general industry companies, each of which demonstrate that the Company's non-union wages are at levels consistent with those offered by the comparison companies (see, e.g., Exh. KEDNE/JCO-9; Exh. KEDNE/JCO-10; Exh. AG-10-1 **CONFIDENTIAL**; Exh. AG-10-8 **CONFIDENTIAL**). The Attorney General ignores all of the studies and evidence presented by the Company and focuses instead on a labeling error made to the Company's exhibit demonstrating a comparison of union wages to argue that the entirety of the Company's compensation analysis should be disregarded.

Second, the Department's standard is that increases for non-union salaries and wages will be allowed when the utility is able to demonstrate that the increases are reasonable and in line with the salaries and wages of *the employees at similarly situated companies that compete for skilled employees*. See The Berkshire Gas Company, D.T.E. 01-56, at 54 (2002); Massachusetts Electric Company, D.P.U. 92-78, at 25-26; Bay State Gas Company, D.P.U. 92-111, at 102-103. As a result, the Department's standard is broader than the interpretation relied on by the Attorney General. The Department has not directed utility companies seeking to establish the reasonableness of their wages in the context of a rate case to compare their wage levels only to companies that sell the same energy commodity. Rather, the Department has allowed utilities to compare their wage levels to other regulated and non-regulated companies that compete for the same employees as the utility performing the comparison, whether or not such utility companies sell the same commodity as the petitioning utility. See, e.g., D.T.E. 01-56, at 57; D.T.E. 02-24/25, at 95.

The Department's standard is appropriate because, given the nature of the Massachusetts (and New England) gas distribution industry, there are no companies that are directly comparable to Boston Gas. See, D.T.E. 01-56, at 57. In addition, the Company's comparison is designed to evaluate non-union or management-level wages and salaries and there are many instances where management personnel will shift between the gas and electric industry. In fact, as is the case with most all of the local gas distribution companies operating in the Commonwealth, the Company functions as part of a multi-state holding company that includes both gas and electric utilities and the Company's management personnel include individuals from both industries. Therefore, the Company competes directly with electric utilities to attract similarly skilled employees. Accordingly, the Company properly compared its wage levels with gas and electric companies, and also general industry, to determine whether its compensation levels are reasonable and appropriate. Therefore, the Department should reject the Attorney General's claim that the Company should compare its wage levels only to local gas distribution companies in New England in order to determine the reasonableness of the Company's non-union wage increases.

Third, the Department's standard does not require that the Company's total compensation be equal to or less than the average or the median of the comparison group. In this case, the Company has presented a comprehensive cost study that demonstrates that Boston Gas is an above average cost performer in the Northeast gas industry. Exh. KEDNE/LRK-3. Since the Company's employee compensation expenses total roughly 66 percent of its total O&M expense level, the record shows that the efficiency of the Company's operations offsets the higher employee compensation costs, to the extent that the Company's compensation levels are, in fact, higher than either the average or median level of the peer group, as the Attorney General claims.

Fourth, the Attorney General's claims regarding the Company's incentive compensation payments should be rejected because under Department precedent, the "reasonableness" of employee compensation is evaluated on a total compensation basis, not in terms of the comparison of union and non-union incentive payments or in terms of the absolute value of an incentive payment (i.e., "ranging as high as $22,000") in isolation. The Department's precedent is clear that compensation is evaluated from a total compensation perspective because different components of employee compensation are substitutable, and may be used in different combinations to attract and retain employees. D.P.U. 93-60, at 122-123. In addition, the Department should reject the Attorney General claims that some of the incentive goals are "too subjective and/or the weight attributed is disproportional" and that the Company has not demonstrated a customer benefit because the Attorney General cites to no evidence or other rational basis that (1) the goals are "too" subjective or that the weight is "disproportional;" and (2) or to contravene the evidence on the record regarding the customer benefit of the incentive compensation program.[46]

All of the claims raised by the Attorney General regarding non-union compensation levels are without merit. The Attorney General's claims do not rest on record evidence, nor has the Attorney General accurately applied Department's ratemaking precedent. The Company has provided documentation of its post-test year

[46] Notably, the record shows that the employee benefits referenced by the Attorney General at page 69, including scholarship programs, health-club benefits, safety-shoe allowances and longevity awards, are provided to **union** employees through collective bargaining agreements, and therefore are not "substitutes" for non-union wages as claimed by the Attorney General.

increases to non-union payroll and incentive compensation expense and has provided appropriate and accurate comparisons of similarly situated gas and electric companies to establish that its total compensation levels, including incentive compensation, are reasonable. The Company has provided information on the efforts that it undertakes to minimize total unit-labor costs consistent with its business strategy. The Attorney General has not provided any legal or factual basis upon which to deny the Company's claims, and therefore, those claims must be rejected by the Department.

(x) There Is No Basis to Excluded Cash Payments from the Test Year Cost of Service.

The Company has included in its cost of service expenses for the test year payments to its employees that represent performance recognition awards for exemplary performance to the Company (RR-AG-100). The Attorney General contends that such expenses should not be included in the Company's cost of service, claiming that such payments represent one-time, non-recurring expenses (Attorney General at 70). To the contrary, the record shows that the Company's "Above and Beyond" awards are granted periodically in recognition for superior performance on a special project or other business initiative (RR-AG-100). For example, the Company granted such payments during the test year to individuals that aided the Company in successfully implementing its CRIS billing system, which, if not completed properly or on time, would have resulted in significant costs to the Company (id.). Because such payments recur periodically, the Department should allow such payments to be included in the Company's cost of service.

(xi) <u>The Company Has Capitalized the Correct Amount of Employee Benefit Costs</u>

The Attorney General asserts that the Company failed to capitalize an appropriate level of its employee benefit costs during the test year (Attorney General at 71). The Attorney General arrives at this conclusion based solely on the fact that employee benefits during the test year were capitalized at a lower percentage (18.45%) than capitalized labor costs (28.64%). The Attorney General proposes an adjustment to the cost of service that would decrease total employee benefits costs by $3,384,833 by increasing the amount of capitalized employee benefits to the same 28.64 percent that capitalized labor is to total wages and salaries.

The Attorney General's proposed adjustment is inappropriate and is not supported by record evidence. The record demonstrates that over the past five years, the percentage of employee benefits capitalized has always been different from the percentage of capitalized labor. Exh. AG 1-40. The rate at which employee benefits are capitalized will vary based on the type and mix of capital projects that the Company undertakes in any given year and the type and mix of employees engaged in those projects. Tr. 5, at 532-535. During the test year a significant amount of labor relating to the implementation of the CRIS system was capitalized and this capital project was supported by administrative personnel assigned to the service company. The process for capitalizing employee benefits relating to these types of service company personnel varies from the capitalization of field personnel engaged in construction activities. Accordingly, the amount of capitalized employee benefits will never be the same as the percentage of capitalized labor in any given year or from year to year.

In any year where there is a major increase in the portion of the Company's capitalized labor that is related to non-construction projects and involves service company employees the variation in the percentage of capitalized employee benefits will increase from the percentage of capitalized labor expense. It is for exactly this reason that there was a wider variation than normal between the amount of capitalized employee benefits and capitalized labor costs. This variation coincides with the increase in capitalized labor costs related to non-construction activities and the involvement of a significantly greater number of employees other than field personnel. Accordingly, the adjustment proposed by the Attorney General is without merit, is unsupported by the record and fails to give appropriate consideration to the type of employees that were engaged in test year capital projects.

(xii) The Company Has Already Removed All Costs Associated with Shareholder Services from the Cost of Service

The Attorney General claims that the Company has failed to remove expenses for shareholder services from the Company's cost of service (Attorney General at 72-73). However, the record shows that the Company has removed these expenses from its cost of service (Tr. 23, at 3145). Accordingly, the Attorney General's point on this issue is moot.

(xiii) The Company's Rate Case Expenses are Reasonable and Appropriate for Recovery Through Rates.

The Company has estimated that the rate-case expense to litigate this proceeding will total approximately $1,665,289, including the cost of researching, preparing and litigating this filing through the compliance phase of the proceeding (Exh. KEDNE/PJM-1, at 22). The cost includes expenses associated with: (1) legal representation; (2) research and preparation of a productivity and cost study to support the price-cap component of the Company's PBR plan; (3) research and preparation of the cost of capital analysis; (4) preparation of a lead/lag study; and (5) other associated costs that are incurred to complete the case (i.e., temporary office help, office supplies, travel expenses) (id. at 23). The Company proposes to amortize this expense over the five-year term of the price-cap plan (Exh. KEDNE/PJM-1, at 24). This results in an annual expense amount of $333,058 (Exh. KEDNE/PJM-1, at 24).

As demonstrated on the record and consistent with the Department's standard, the Company has requested recovery of only documented known and measurable rate case expenses. Exh. KEDNE/PJM-1 at 22-24; Tr. 14, at 1872-1875. See also Berkshire Gas Company, D.T.E. 01-56, at 72**;** Fitchburg Gas and Electric Company, D.T.E. 02-24/02-25, at 190-191; Boston Gas, D.P.U. 96-50 (Phase I), at 77. In accordance with its precedent, the Department will allow a company to recover known and measurable rate case expenses incurred for the use of outside legal and consulting services procured without a competitive bidding process if the company provides adequate justification for its decision to do so. Berkshire Gas Company, D.T.E. 01-56, at 73 (2001). Fitchburg Gas and Electric Light Company, D.T.E. 02-24/02-25, at 193 (2002).

As the record indicates, the Company did not engage in a competitive bidding process to secure outside services to support the Company in this proceeding because the consultants and legal representatives involved in this case are in the best position to provide the Company with cost-effective services (Exh. KEDNE/PJM-1, at 2; Tr. 14, at 1872). For example, the Company's regulatory law firm, Keegan, Werlin & Pabian, LLP, has a longstanding working relationship with the Company and its distribution company affiliates and has a thorough knowledge of the Company's finances, operations and ratemaking practices (Exh. KEDNE/PJM-1, at 24; Tr. 14, at 1872). Moreover, the firm has represented the Company in several major proceedings before the Department, including proceedings approving the mergers of Eastern Enterprises with Essex and Colonial (id.). In addition, the law firm has in-depth experience with utility rate and regulatory issues, especially in Massachusetts (Exh. KEDNE/PJM-1, at 24). The combination of these factors has allowed the Company to prepare and litigate its rate case in a cost-effective manner. In addition, the Company has contained its rate-case legal expenses by utilizing in-house resources to the maximum extent possible (Tr. 25, at 3482).

The Attorney General challenges the Company's rate case legal expenses by: (1) claiming that the Company should have issued an RFP for legal services; and (2) alleging that the Company failed to receive a discount from its regulatory counsel from counsel's "current billing rate" (Attorney General at 74). However, the Company has provided sufficient rationale to establish that its use of its long-standing regulatory counsel for its rate case preparation was more cost-effective than using another law firm. In addition, the Attorney General has misrepresented the record regarding the discount provided by the Company's regulatory counsel. The record shows that the Company's regulatory counsel offered to provide the Company with legal services in connection with this rate case at rates that represented a twenty percent discount from the firm's "current billing rate" (Attorney General at 74, citing Exh. AG-5-2, Tr. 25, at 3482-3488, 3499-3500; see also Tr. 25, at 3481-2). This means that the rates charged to Boston Gas for this proceeding, as well as other regulatory matters in 2002, were provided at a discount to the regular billing rates of the firm. The fact that the Company secured the same discount for other legal work that was captured in the test-year expense should not count against the Company. Therefore, the Attorney General's argument regarding the firm's billing rates should be disregarded.[47] Moreover, the Attorney General has failed to support his contentions regarding the reasonableness of the Company's rate case legal expenses and, therefore, the Department should reject the Attorney General's arguments.

Similarly, as shown on the record, the other consultants retained by the Company to prepare and support the Company's rate case filing have longstanding relationships with the Company, as well as substantial and unique expertise in utility ratemaking issues (Exh. KEDNE/PJM-1, at 24). Specifically, Dr. Kaufmann was involved in the development of the productivity analysis supporting the Company's PBR proposals in D.P.U. 96-50, and therefore, is uniquely situated to perform the studies and analyses needed to update the 1996 study, which involves the use of a proprietary database and modeling routine (id.). It is counterintuitive to imply, as the Attorney General does in his Initial Brief, that another consultant could more efficiently prepare a productivity analysis for the Company for purposes of this proceeding when the Pacific Economics Group and Dr. Kaufmann, in particular, have already invested the time and expense to gather the necessary data for the Company in preparation of the PBR analysis. Had the Company

[47] The Attorney General has also misinterpreted notations on the legal bills filed by the Company with respect to items referencing a purported "2001 Rate Case" (Attorney General at 75, citing Exh. AG-5-6 [supp.2], at 76-88). As noted by Mr. Bodanza, the Company investigated the necessity of filing a rate case during the year 2002, but ultimately rejected that option (Tr. 12, at 1541-1542). However, the work performed by the Company's regulatory counsel related to that internal investigation was carried over and used in the present rate case and is not distinguishable as being applicable to an "abandoned" rate case. Accordingly, the Company has properly included these test-year expenses in its cost-of-service calculation.

used another consultant, the consultant would not have had the database available, and significantly more costs would have been involved in recreating the database.

Lastly, the Company's proposal to amortize the rate case expenses over the five-years that the PBR Plan will be in effect is in accordance with the Department's precedent and should be allowed. See Boston Gas Company, D.P.U. 96-50, at 78-79 (wherein the Department held that, where a company is subject to a price-cap plan, and the term of the price cap plan exceeds the average period between a company's three most recent rate cases, the rate case expenses should be amortized over the term of the price cap plan). This results in an annual expense amount of $333,058, which is the test-year adjustment that the Company is proposing in this case (id.). Accordingly, the Company has demonstrated that its rate case expenses are known, measurable and reasonable in amount and properly included in the Company's cost of service.

D. Cost of Capital

1. Standard of Review

The Department's longstanding precedent requires that a company's allowed return on equity be established at a level that will "preserve the company's financial integrity, allow it to attract capital on reasonable terms, and be comparable to returns on investments of comparable risk." Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 79 (2001), citing Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia, 262 U.S. 679 (1923); Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1942). See also, Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 229 (2002); The Berkshire Gas Company, D.T.E. 01-56, at 116-119 (2002).

In using a model-based return-on-equity analysis, a number of judgments are required. Fitchburg Gas and Electric Light Company, D.T.E. 02-24/25, at 229 (2002).

> One looks for substantial evidence on which one may reasonably rely to base a judgment. Each level of judgment to be made contains [a] possibility of inherent bias and other limitations.

Id., citing, D.T.E. 01-56, at 117; Western Massachusetts Electric Company, D.P.U. 18731, at 59 (1977).

> There may be science, but there is also some art involved; and acknowledging as much does not diminish the value of the comparative exercise when properly conducted.

Fitchburg Gas and Electric Light Company, D.T.E. 99-118, at 80 (2001). The end result of the Department's rate-of-return allowance must provide a utility with the opportunity to cover its interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be adequate to attract capital in all market conditions, be commensurate with the risk to which the utility's capital is exposed and support reasonable quality (Exh KEDNE/PRM-1, at 6).

2. The Company's Proposed Capital Structure Is Reasonable

The plant-in-service and capitalization recorded on the Company's financial books at test year-end included the acquisition premium or "goodwill" allocated to the books of Boston Gas following the merger of KeySpan and Eastern Enterprises (Exh. KEDNE/PJM-1 at 36; Exh. KEDNE/PJM-2, at 36). The unamortized balance of this goodwill totaled $790,284,582, as of December 31, 2002 (Exh. KEDNE/PJM-1, at 36). The capitalization associated with the goodwill existing on the Company's books is discrete and identifiable because it was transferred to the Company's books through journal entries made at the time of the merger (id.). Therefore, the Company has removed the capitalization associated with the goodwill removed from the plant in service, which is composed of $650,000,000 in debt and $140,284,582 in equity (id.; Tr. at [x]); See New England Power Company, D.T.E. 00-53 (2000) (The intangibility of goodwill renders it inappropriate for consideration as a component in a utility's capitalization for purposes of G.L. c. 164, § 14).[48] The Company also adjusted preferred stock by $1,500,000, to reflect its upcoming redemption in September 2003 (Exh. KEDNE/PJM-1, at 36). The removal of goodwill and the redemption of $1,500,000 in preferred stock results in a capital structure that is 32.01 percent long-term debt, 1.88 percent preferred stock, and 66.11 percent equity (id.).

The removal of the capitalization attributable to goodwill results in a relatively high equity ratio that is atypical for utility ratemaking purposes. Therefore, in order to maintain a reasonable debt-to-equity ratio that is consistent with the regulated utility industry, it is appropriate in this case to impute an equity component of 50 percent for purposes of calculating the weighted cost of capital (id.). This change results in a capital structure that is 48.16 percent long-term debt, 1.84 percent preferred stock and 50 percent equity (id.). As discussed in Mr. Moul's testimony, the common equity ratio of 50 percent is: (1) representative of the capital structure of the Barometer Group (see Exhibit KEDNE/PRM-1, at 21); (2) compatible with the ratio expected by the rating agencies for

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48 The removal of goodwill from the asset side of the balance sheet requires an equal amount be removed from a company's total capitalization. Where it can be determined in what manner the goodwill was funded (e.g., 100 percent equity), the capitalization should be reversed in the same manner. See New England Power Company, D.T.E. 00-53 (2000). Where it cannot be directly attributed to a particular financing, the Department has allowed a pro rata reduction to a company's capitalization. See Southern Union Company, D.T.E. 01-52, at 5, ftnt.7 (2001).

an A credit-quality rating (see Exhibit KEDNE/PRM-1, at 19), and (3) has been accepted by the Department in previous rate cases and financial proceedings (Exh. AG-14-10).

> Where a capital structure has been found to deviate substantially from sound and well-established utility practice, the Department has imposed a hypothetical structure of 50 percent debt and 50 percent common equity for ratemaking purposes.

Blackstone Gas Company, D.T.E. 01-50, at 25 (2001). See also Pinehills Water Company, D.T.E. 01-42, at 18 (2001) (the Department imposes a hypothetical capital structure of 50 percent debt and 50 percent equity for ratemaking purposes), citing Assabet Water Company, D.P.U. 95-92, at 33 (1996); Kings Grant Water Company, D.P.U. 91-252, at 17 (1992); Wylde Wood Water Works, D.P.U. 86-93, at 23 (1987); Blackstone Gas Company, D.P.U. 1135, at 4 (1982).

In addition, the common equity ratio of 50 percent is consistent with the Company's equity capitalization ratio for permanent capital (i.e., capital excluding short-term debt) in the years leading up to the merger (1997 through 2000), as shown below:

Capital Structure Ratios Based on Permanent Capital	**1997**	**1998**	**1999**	**2000**
Long-Term Debt	43.4%	41.1%	42.0%	44.1%
Preferred Stock	6.0%	5.7%	4.9%	3.3%
Common Equity	50.6%	53.2%	53.0%	52.6%

Exh. KEDNE/PRM-2, at 2.

The Company calculated its weighted average cost of long-term debt by multiplying the amount of each outstanding long-term debt instrument by its respective coupon rate. The sum of the long-term debt interest expense was then divided by the total amount of outstanding debt to determine the weighted average cost of long-term debt. Amortization of debt-issuance expense was included in the coupon rate of each instrument (Exh. KEDNE/PJM-1, at 37). This calculation results in a weighted average cost of long-term debt of 8.14 percent (id.). Listed below is the calculation of the Company's weighted average cost of capital, which is 10.13 percent.

	Imputed Capital Structure	**Cost**	**Cost of Capital (Col B x Col C)**
Long-Term Debt	48.16%	8.14%	3.92%
Preferred Stock	1.84%	6.42%	0.12%
Common Equity	50.00%	12.18%	6.09%
Weighted Avg. Cost of Capital			**10.13%**

Exh. KEDNE/PJM-2, at 36.

The Attorney General argues that the Department should reject the Company's proposal to reduce its debt ratio from 59.4 percent to 48.16 percent and replace it with an imputed 50/50 capital structure (Attorney General at 78). According to the Attorney General, the $650 million in debt issued to Boston Gas "did not result from merger requirements," and even if it did, the Company should not be permitted to eliminate this debt from the Boston Gas balance sheet because this level of debt is consistent with market expectations for similar "A" rated companies (id.). The Attorney General suggests that the Department should use the cost of the Company's debt issuance to KeySpan for all debt in the capital structure that it determines is appropriate "over and above the $210 million amount issued in 1995" (id.). The Department's precedent and the record evidence in this case strongly contradict the Attorney General's position.

On November 8, 2000, KeySpan Corporation merged with Eastern Enterprises, which resulted in the acquisition of Boston Gas. As described above, KeySpan booked an acquisition premium as goodwill on its balance sheet as of the date of the merger, which was later "pushed down" to the operating companies, including Boston Gas. The capitalization associated with the goodwill existed on the Company's books is discrete and identifiable because it was transferred on the Company's books through journal entries made at the time of the merger (Exh. KEDNE/PJM-1, at 36; Exh. DTE-4-13). The unamortized balance of this goodwill was approximately $790 million as of the end of the test year, December 31, 2002 (id.). Although the acquisition premium is booked as a goodwill "asset" on the Company's balance sheet, it is not included in the Company's rate base, nor is it otherwise recoverable in rates from the Company's customers as a utility-regulated cost of service.

It is well-established that the Department excludes that portion of a company's capitalization attributable to a company's assets that are not included in rates (e.g., goodwill and other non-utility assets associated with unregulated operations).

> [T]he Company's proposed adjustment for acquisition premiums is appropriate, given that an acquisition premium, or goodwill, is intangible and, as such, should be excluded as a component in a utility's plant for purposes of G.L. c. 164, § 16 (citations omitted).

Southern Union Company, D.T.E. 02-27, at 12 (2002). See also New England Power Company, D.T.E. 00-53 (2000). Accordingly, the Company has removed from its capital structure the goodwill attributable to the Eastern merger.

The Attorney General's charge that the $650 million in debt pushed down at the time of the acquisition to Boston Gas "did not result from merger requirements," is without merit. As described in the Company's SEC 10K Report for the year ending December 31, 2002, this debt resulted from the "push down" accounting requirements, which is booked as an advance from KeySpan to the Company (Exh. AG 1-2, Boston Gas Company 10K Report, 2002, Notes to Financial Statements, at F-7).[49] The Company's journal entries support the specific charges described in the Company's SEC 10K Report (Exh. AG-4-13, Merger Journal Entries, Item no. 9) (Advances from KeySpan $650,000,000).

Therefore, the Company has established on this record that its proposed capital structure is reasonable, consistent with Department precedent and should be approved.

3. The Company's Proposed Return on Equity Is Fair and Reasonable

Mr. Moul testified that, based on his detailed analysis, the Company's proposed rate of return on common equity should be 12.18 percent, and its overall rate of return should be 10.13 percent (Exh. KEDNE/PRM-1, at 2). This rate of return on common equity is established using capital market and financial data relied upon by investors when assessing the relative risk and corresponding return on equity required for a gas distribution utility such as Boston Gas (id. at 4). Mr. Moul relied on four well-recognized measures of the cost of equity: (1) the Discounted Cash Flow ("DCF") model; (2) the Risk Premium ("RP") analysis; (3) the Capital Asset Pricing Model ("CAPM"); and (4) the Capital Earnings ("CE") approach. In general, the use of more than one approach provides a superior foundation to arrive at the cost of equity (id. at 5). Using each of these four traditional approaches to the determination of the Company's cost of equity,

[49] Consistent with generally accepted accounting principles ("GAAP"), the Company adjusted the goodwill on the books of Boston Gas from $600 million to $650 million to reflect a redistribution of the goodwill attributable to the acquisition premium (Tr. 497-502 [McClellan]).

Mr. Moul relied upon data from a proxy group of eight gas distribution companies (the "Barometer Group").[50] Mr. Moul used group average data for the Barometer Group (in contrast to individual company cost of equity) to minimize the effect of extraneous influences, such as the effects of restructuring, on the market data for an individual company (id.). The cost of equity using each of these approaches is as follows:

Calculated Cost of Equity

Methodology	**Cost of Equity**
Discounted Cash Flow	12.10%
Risk Premium	12.25%
Capital Asset Pricing Model	14.64%
Capital Earnings	13.90%

Id. at 5.

The Department has previously recognized the usefulness of the DCF and Risk Premium measures when considering the cost of equity. Commonwealth Gas Company, D.P.U. 87-122, at 106 (1987) ("The Department finds that a properly conducted risk premium and/or DCF analysis can provide insight into the true equity return sought by utility investors"). These measures provide a cost of equity of 12.18 percent (12.10% + 12.25% = 24.35% /2).[51] This is a conservative estimate of the Company's cost of common equity and is near the lower end of the range of cost estimates produced by the four alternative methods. The 12.18 percent cost of equity recommendation is also

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50 The Barometer Group consists of the following companies: AGL Resources, Inc., Atmos Energy Corporation, New Jersey Resources Corp., NICOR, Inc. Peoples Energy, Piedmont Natural Gas Co., South Jersey Industries, Inc., and WGL Holdings, Inc. (Exh. KEDNE/PRM-2, at 5).

51 The mean and median of all four methods is 13.22 percent and 13.08 percent, respectively (Exh. KEDNE/PRM-1, at 5).

conservative because it makes no provision for the prospect that the rate of return may not be achieved because of unforeseen events that occur during the effective period of the Company's proposed PBR plan (Exh. KEDNE/PRM-1, at 6). Accordingly, a return on common equity of 12.18 percent is appropriate and reasonable in this case.

4. The Barometer Group Provides a Reasonable Basis for Measuring the Company's Cost of Equity.

Because the Company is an indirect wholly-owned subsidiary of KeySpan Corporation, it is difficult to assess directly investors' expectations of the Company's required return. Therefore, the Company provided an analysis of eight companies that are considered to be of generally comparable risk to that of the Company. The Barometer Group includes companies that: (i) are engaged in similar business lines; (ii) have publicly-traded common stock that is listed on the New York Stock Exchange; (iii) are contained in *The Value Line Investment Survey* in the industry group entitled "Natural Gas Distribution," (iv) have operations in the Northeastern, Great Lakes and Southeastern regions of the U.S.; (v) have not cut or omitted their dividend, (vi) have at least 70 percent of their assets represented by gas operations; and (vii) are not currently the target of a merger or acquisition (Exh. KEDNE/PJM-1, at 15-16).[52]

To determine the Company's comparable risk to the Barometer Group, the Company examined a variety of important categories of relative risk over the period 1997 through 2001. The Company also performed a fundamental risk analysis comparing the Company to the Barometer Group and S&P Public Utilities for the same time period.[53]

[52] Seventy-eight percent of the Barometer Group's revenue is from the gas utility business; 96 percent of its income and 91 percent of its identifiable assets similarly are from the gas utility business (Exh. KEDNE/PRM-1, at 17).

[53] In conducting its risk analysis, the Company modified its financial data from Standard & Poor's COMPUSTAT to remove the impact of merger-related items (Exh. KEDNE/PRM-1, at 19).

In particular, the Company examined the categories of relative risk identified in Table 1, attached (Exh. KEDNE/PRM-1, at 19-24). In many respects, the risk of Boston Gas parallels that of the Barometer Group. However, in one important aspect related to its more variable earned returns, the Company's risk is *higher* than that of the Barometer Group (id. at 24). In the categories of financial risk, operating ratios, quality of earnings and the ratio of Internally Generated Funds to construction, the Company is similar to the Barometer Group. On balance, the Barometer Group provides a reasonable basis for measuring the Company's cost of equity.

5. The Company's DCF Analysis Is Reasonable

As indicated above, the Department has previously recognized the usefulness of the DCF when considering the cost of equity. The DCF model seeks to explain the value of an asset (common stock) as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. The future expected cash flows consist of a current cash (dividend) yield and future price appreciation (growth) of the investment (Exh. KEDNE/PRM-1, at 25). The cost of equity based on a combination of these two components represents the total return that investors can expect for an equity investment. The DCF model is represented by the following equation:

$$Ks = \frac{D_0(1+g)}{P_0} + g$$

Where K_s = the annual rate of return on common equity required by investors to induce them to hold a firm's common stock.

D_0 = the annual dividend (with time subscripts).

P_0 = the price of a single share of common stock

g = the expected growth rate.

Exhibit KEDNE/PRM-3, at E-3.

As a basis for determining the dividend yield component of the DCF model, the Company calculated a 5.11 percent average yield for the six-month period June through December 2002 for the Barometer Group (Exh. KEDNE/PRM-1 at 27-28). The use of this dividend yield will reflect current capital costs while avoiding "spot" yields (id. at 28). Mr. Moul adjusted the average dividend yield to reflect the prospective nature of the dividend payments (i.e., the higher expected dividends for the future) by using the average of three calculated adjusted values, resulting in an adjusted dividend yield of 5.28 percent for the Barometer Group.

To derive the growth rate for the Barometer Group, Mr. Moul analyzed the following two indicators: (1) the five-year and ten-year historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share; and (2) five-year forecast growth rates for earnings per share, dividends per share, book value per share and cash flow per share, as provided in IBES, Zacks, First Call, Market Guide and the Value Line publications (id. at 29-31). The growth rates included in these publications are consensus forecasts taken from a survey of analysts that make projections of growth for these companies, and represent reliable authorities of projected growth upon which investors rely (id. at 30, 33). Forecasts that encompass growth for the next five years provide the best available information that influences expected returns, and *earnings per share* projections by financial analysts represent the growth indicators most indicative of investor expected growth for a firm (id. at 31-32).[54]

[54] Historical evidence does not presently represent a good measure of growth for the Barometer Group companies because of the more recent massive restructuring of the utility industry through deregulation, unbundling, and merger and acquisition activity (Exh. KEDNE/PRM-1, at 32).

For the Barometer Group, the forecasts of earnings-per-share data provide strong evidentiary support for a prospective growth rate of 6.00 percent. The reasonable expectation of 6.00 percent growth rate is within the array of earnings per share growth rates shown by the analysts forecasts (id. at 33). The restructuring and consolidation now taking place in the utility industry will provide additional risks and opportunities as the utility industry adapts to a new business environment. Expectations concerning mergers and acquisition activities also will affect stock prices. Accordingly, the traditional DCF calculation would understate the required cost of equity (id. at 34).

When stock prices in the market diverge from the book values, a market-derived cost of equity cannot be applied directly to the common equity account measured at book value (rate base) in a rate setting context. This is the situation today where the market price of stock exceeds its book value for most utilities. This divergence of market price and book value also creates a difference in the level of financial risk when the capitalization of a utility measured at its market value contains relatively less debt and more equity than the capitalization measured at its book value. Accordingly, it is necessary to adjust the market-determined cost of equity upward to reflect the higher financial risk associated with the book value capitalization of a regulated utility company (id. at 38-41).

> Failure to make this modification would result in a mismatch of the lower financial risk related to market value used to measure the cost of equity and the higher financial risk of the book value capital structure used in the ratesetting process. Because the ratesetting process utilizes the book value capitalization, it is necessary to adjust the market-determined cost of equity for the higher financial risk related to the book value of the capitalization.

Id. at 39.

The DCF-determined cost of equity is adjusted for the financial risk associated with the book value of the capitalization through the use of a leverage adjustment. Research conducted by Nobel laureates Modigliani and Miller has established that as the borrowing of a firm increases, the expected return on stockholders' equity also increases (id.). This Modigliani and Miller theory shows that the cost of equity increases by 0.82 percent when the book value of equity rather than the market value of equity is used for ratemaking purposes (id. at 40). The resulting DCF cost rate is:

$$\begin{array}{ccccccc} D_1/P_0 & + & g & + & \text{leverage adjustment} & = & k \\ 5.28\% & + & 6.00\% & + & 0.82\% & = & 12.10\% \end{array}$$

Accordingly, the Company's DCF analysis is reasonable and results in a growth rate for the Barometer Group of 12.10 percent.

The Attorney General argues that Mr. Moul improperly relies on short-term earnings per share forecasts to determine a DCF growth rate of 6.0 percent, resulting in an "upward bias" (Attorney General Initial Brief at 83-84). By comparison, the Attorney General references Mr. Moul's estimated growth rate of 5.5 percent in the Company's last rate case, D.P.U. 96-50 (id. at 83). The Attorney General compares the Company's DCF growth rate to the 5.5 percent long-run consensus growth rate forecast of the overall economy (id. at 84). Based on five-year historical and forecasted growth rates for earnings per share and book value per share, the Attorney General inexplicably suggests a 4.0 percent DCF growth rate "would be a reasonable estimate" (id.). The Attorney General maintains that an appropriate proxy for the current dividend yield is 4.88 percent, resulting in a DCF cost of common equity of 8.99 percent (id. at 84-85). The Attorney General's challenge to the Company's DCF is without merit and should be rejected.

The Attorney General's proposed growth rate of 4.0 percent appears to have been pulled out of thin air, without any evidentiary foundation, theoretical justification or academic support. There is none, and it is woefully and substantially too low. The Attorney General's reference to Mr. Moul's estimated growth rate in the Company's last rate case, D.P.U. 96-50 is misplaced. The proxy group in D.P.U. 96-50 included Bay State Gas Company, Connecticut Energy, Connecticut Natural Gas and Indiana Energy. Each of these companies no longer exists as an independent company as a result of mergers that have occurred in the industry, and are thus no longer included in the current Barometer Group. Nor is Laclede Gas in the current Barometer Group, although it was included in D.P.U. 96-50. Therefore, the Attorney General is comparing apples to oranges when he measures the Barometer Group in D.P.U. 96-50 against the Barometer Group in this case.

The Attorney General's reference to the 5.5 percent growth rate forecast in the overall economy is similarly flawed. Mr. Moul testified that there is an inadequate evidentiary foundation for the selection of the GDP to represent the long-term growth in the DCF (Exh. KEDNE/PRM-1, at 35). Moreover, forecasts of GDP growth rate are well known to financial analysts and are already incorporated into more specific industry performance growth rates to the extent the affect an individual firm (id.). GDP is a measure of demand which would represent growth in revenues, not corporate profits (id. at 37). Empirical evidence also demonstrates that GDP growth has not set a limit on long-term growth, nor is it expected to in the future (id. at 35). As reported in the October 10, 2002 issue of *Blue Chip*, long-term growth in corporate profits far exceed those of GDP.

Year	Nominal GDP	Corporate Profits, Pretax
2004	5.5%	8.8%
2005	5.4	7.4
2006	5.3	6.5
2007	5.3	6.4
2008	5.2	5.9
2004-2008 average	5.3	7.0
2009-2013 average	5.4	6.3

Exh. KEDNE/PRM-1, at 37. Put simply, growth in GDP does not account for the specific growth fundamentals of a company because it does not recognize that a firm's management can skillfully produce profits that exceed some generic benchmark (id. at 37).

The Attorney General's reliance on growth in dividends an attempt to choose the lowest available growth rate, and is not based on a sound, academically supported approach for use in DCF growth analysis. The growth in the share value is most relevant to investors' total return expectations rather than dividend growth, which represents only one component of an investor's expectation of her total return (id. at 31). Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, established that the best measure of growth in the DCF model is forecasts of earnings per share growth (id. at 32, citing *Choice Among Methods of Estimating Share Yield*, The Journal of Portfolio Management, Spring 1989, Gordon, Gordon & Gould).

As shown below, using the remaining indices identified by the Attorney General and cash flow per share growth that the Attorney General conveniently ignored (i.e., earnings per share, book value per share and cash flow per share), on a forecasted basis, provides an overall DCF growth rate of 5.73 percent. Combining this growth with the 6.9 percent forecast growth in corporate profit (see Exh. AG-14-19, Blue Chip, March 10,

2003) provides overall growth of 6.32 percent. This would translate into a return on equity of 12.34 percent when the DCF cost rate is applied to book value.

Growth Component	Growth Rate
Forecast growth rate in earnings per share	6.69%
Forecast growth rate in book value per share	5.13%
Forecast growth rate in cash flow per share	5.38%
Average of forecasted growth rates (lines 1+2+3/3)[55]	5.73%
Forecast of growth in corporate profits Exh. AG-14-9 (March 10, 2003 Blue Chip)	6.9%
Average of lines 4 and 5	6.32%

Based on the April 2003 dividend yields, which are properly synchronized with the growth rates described above, results in the following DCF cost of common equity:

	Growth Rate at 6.32%
Current Dividend Yield[56]	5.04%
DCF Dividend Yield[57]	5.20%
Growth Rate	6.32%
DCF Cost of Common Equity	11.52%
Adjusted DCF Cost of Common Equity [additional return to reflect additional financial risk of return on book value as compared to market value]	12.34%

55 Information in lines 1 through 3 is taken from Exh. AG-14-20.

56 Exh. AG-14-16, at 1.

57 See Exh. KEDNE/PRM-3, at Appendix E.

The Attorney General argues that the dividend yield component of the DCF Model is best analyzed using the most recent six-month dividend yield average of 4.88 percent (Attorney General Initial Brief at 82). Although the Company does not object to that portion of the Attorney General's proposal to use an unadjusted dividend yield on based on a six-month period, the specific six-month period selected by the Attorney General (the period ending June 2003) is inconsistent with the period selected by the Attorney General to establish the risk-free rate of return (the period ending April 2003). The average used by the Attorney General appears to have been specifically selected for its end result because he selected a period of historically low interest rates that would produce a downward bias (RR-AG-67). The more defensible approach would be to use the dividend yield average of 5.04 percent for the six-month period ending April 2003 (Exh. AG-14-16). This dividend yield is the most consistent and reasonable value to use because all of the growth rate data cited by the Attorney General concluded around this same time period (see Exh. AG-14-18 and Exh. AG-14-20). As Mr. Moul testified:

> Question: Would it be appropriate for the Department to use these updates in its analysis of the DCF model?
>
> Answer: They would only be appropriate if everything was synchronized. In other words, we wouldn't want to be picking and choosing data inputs and mixing a growth rate from one period of time with, say, dividend yields from a different period of time."

(Tr. 1952 [Moul]). The Attorney General's failure to synchronize the dividend yield and growth rates leads to a meaningless measure of the cost of equity.

6. The Company's Risk Premium Analysis Is Reasonable

The Risk Premium approach recognizes the required compensation for the more risky common equity over the less risky secured debt position of a bond holder (Exh.

KEDNE/PRM-3, at Appendix G-2). The cost of equity stated in terms of Risk Premium analysis is the following:

$$K = i + RP$$

where K = the cost of equity
i = the interest rate on long-term public utility debt
RP = (risk premium), which represents the additional compensation above bond interest rates that is required for riskier common equity

Id. The Company relied upon historical long-term interest rates and forecast yields on A-rated public utility debt to establish its 7.25 percent prospective yield on long-term A-rated public utility bonds (Exh. KEDNE/PRM-1, at 41). Mr. Moul determined the forecast yields on A-rated public utility debt by using the *Blue Chip Financial Forecasts* ("Blue Chip"), plus 2.00 percent (which represents the interest rate spread between the yields on long-term Treasury bonds and A-rated public utility bonds) (Exh. KEDNE/PRM-3, Appendix F). The Blue Chip is a reliable authority that contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage and investment advisory services.[58] To independently project the forecast of the yields on A-rated public utility bonds, Mr. Moul testified that he combined the forecast yields on long-term Treasury bonds published on January 1, 2003 and the yield spread of 2.00 percent interest rate yield spread described above. As shown below, the A-rated utility-bond yields range from 7.1 percent to 7.8 percent.

58 In early 1999, Blue Chip discontinued publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15 (Exh. KEDNE/PRM-1, at 42).

	Blue Chip Financial Forecasts				
	Corporate bonds		Long-term	A-rated Utility	
Quarter	Aaa rated	Baa rated	Average	Spread	Yield
1st Qtr. 2003	6.3%	7.5%	5.1%	2.0%	7.1%
2nd Qtr. 2003	6.3	7.5	5.2	2.0	7.2
3rd Qtr. 2003	6.4	7.6	5.3	2.0	7.3
4th Qtr. 2003	6.6	7.7	5.6	2.0	7.6
1st Qtr. 2004	6.8	7.8	5.7	2.0	7.7
2nd Qtr. 2004	6.9	8.0	5.8	2.0	7.8

Exh. KEDNE/PRM-1, at 42. These forecasts together with the historical long-term interest rates demonstrates that a 7.25 percent yield on A-rated public utility bonds represents a reasonable expectation.

Mr. Moul calculated the equity risk premium by comparing the market returns on utility stocks and the market returns on utility bonds (the "risk rate differential"). To measure the market return on utility stocks, Mr. Moul relied upon the S&P Public Utility index because it represents entities that are engaged in regulated activities rather than a broader market index such as the S&P 500 Composite Index (id. at 43). The risk rate differential between the cost of equity and the yield on long-term corporate bonds can be determined by reference to a comparison of holding period returns (in this case, one year) computed over long time spans. The analysis assumes that over long periods of time investors' expectations are on average consistent with rates of return actually achieved (Exh. KEDNE/PRM-3, at G-3). The returns of the historical holding periods of 1928-2001, 1952-2001, 1974-2001 and 1979-2001, based on the S&P Public Utility Index and Public Utility Bonds, are shown below. The Company used these historical holding period returns in conjunction with the average of: (i) the midpoint of the range shown by the geometric mean and median; and (ii) the arithmetic mean. This procedure provides a comprehensive way of measuring the central tendency of the historical returns (Exh. KEDNE/PRM-1, at 42).

Tabulation of Risk Rate Differentials for
S&P Public Utility Index and Public Utility Bonds
For the Years 1928-2001, 1952-2001, 1974-2001, and 1979-2001

Total Returns	Range: Geometric Mean	Range: Median	Midpoint	Point Estimate Arithmetic Mean	Average of the Midpoint of Range and Point Estimate
1928-2001					
S&P Public Utility Index	8.77%	11.26%		11.11%	
Public Utility Bonds	5.49%	4.55%		5.79%	
Risk Differential	3.28%	6.71%	5.00%	5.32%	5.16%
1952-2001					
S&P Public Utility Index	11.18%	12.05%		12.62%	
Public Utility Bonds	6.30%	5.08%		6.63%	
Risk Differential	4.88%	6.97%	5.93%	5.99%	5.96%
1974-2001					
S&P Public Utility Index	13.45%	14.72%		15.33%	
Public Utility Bonds	9.22%	9.45%		9.61%	
Risk Differential	4.23%	5.27%	4.75%	5.72%	5.24%
1979-2001					
S&P Public Utility Index	14.37%	14.82%		16.07%	
Public Utility Bonds	9.87%	9.45%		10.24%	
Risk Differential	4.50%	5.37%	4.94%	5.83%	5.39%

Exh. KEDNE/PRM-2, Schedule 9. Mr. Moul testified that within the bounds of the highest and lowest risk premium, a common equity risk premium of 5.32 percent was calculated (5.24% + 5.39% = 10.63%/2 = 5.32%) (Exh. KEDNE/PRM-1, at 45). This risk premium was reduced to 5.00 percent to reflect various differences in fundamentals between the Barometer Group and the S&P Public Utilities, including size, market ratios, common equity ratio, return on book equity, operating ratios, coverage, quality of earnings, internally generated funds and betas. As a result, the Risk Premium methodology provides a cost of equity of 12.25 percent.

$$i \quad + \quad RP \quad = \quad k$$

$$7.25\% \quad + \quad 5.00\% \quad = \quad 12.25\%$$

The Attorney General argues that Mr. Moul's Risk Premium analysis is "essentially the same analysis" as his Capital Asset Pricing Model (discussed below) (Attorney General Initial Brief at 90). Noting that Mr. Moul increased his cost of equity recommendations by creating new adjustments "for certain risk factors," the Attorney General maintains that Mr. Moul incorporated a "market-to-book ratio adjustment" (id. at 91). The Attorney General charges that Mr. Moul ignores the increase in risk attributable to the non-utility businesses owned by the companies included in the Barometer Group (id.). The Attorney General's critique of the Company's Risk Premium Analysis demonstrates his fundamental misunderstanding of the Company's methodology and that his arguments are baseless.

The Risk Premium analysis is *not* "essentially the same" as the CAPM analysis. Unlike the CAPM analysis, the Risk Premium analysis is directed specifically to the return required by a utility because it is based on the returns for the S&P Public Utility Index, not a broader market-wide index such as the S&P 500 Composite Index that is used in the CAPM. The Risk Premium analysis uses corporate bond yields as a foundation for the return, and is not limited to measuring systematic risk.

The Attorney General's reference to a "market-to-book adjustment" is misplaced. There is no such adjustment being used in the Company's Risk Premium analysis. Rather, as described in the DCF Model analysis, the Company has incorporated a leverage modification, which is designed to recognize that there is a different financial risk between the market value *capital structure* and the book value *capital structure*. This is *not* a market-to-book ratio adjustment (see Exhibit KEDNE/PRM-1, at 40).

The Attorney General is incorrect that Mr. Moul ignores the purported increase in risk attributable to the non-utility businesses owned by the companies included in the Barometer Group. The Attorney General does not identify the non-utility businesses, their risk characteristics, or their associated return requirements. The Attorney General presents mere conjecture as to the impact, if any, of the non-utility businesses of the Barometer Group companies. To the contrary, Mr. Moul testified that the Barometer Group was carefully assembled to reflect the risk associated with a gas distribution utility business (Exh. KEDNE/PRM-1, at 16-17). In fact, the Barometer Group consists of companies whose gas distribution assets represent 91 percent of total assets, making them predominately regulated gas utilities in the eyes of investors. Any adjustment attributable to the Attorney General's allegation, if made, would not have resulted in any meaningful difference in the required returns (Tr. 15, at 1948 [Moul]). Accordingly, the Attorney General's arguments concerning the Company's Risk Premium analysis are without merit and should be rejected by the Department.

7. The Company's Capital Asset Pricing Model Is Reasonable

The CAPM uses a yield on a risk-free interest-bearing obligation plus a return representing a premium that is proportional to the systematic risk of an investment (Exh. KEDNE/PRM-1, at 46). To compute the cost of equity, three components are used: (1) the risk-free rate of return ("R*f*"); (2) the beta measure of systematic risk ("β"); and (3) the market-risk premium, derived from the total return on the market of equities reduced by the risk-free rate of return ("Rm – R*f*")(id. at 46-47). The overall equation for the CAPM model is the following:

$$Rf + \beta(Rm\text{-}Rf) = k$$

The CAPM accounts for differences in systematic risk (i.e., market risk) between an individual firm and group of firms and the entire market of equities. As a result, a CAPM calculation was performed for the Barometer Group. To measure the risk-free rate of return, Mr. Moul used the yields on long-term Treasury bonds using both historical and forecast data to match the longer-term horizon associated with the ratemaking process (id. at 48). Based on historical and forecast data, the most representative risk-free rate for use in the CAPM is 5.25 percent (id. at 49).

To derive the beta for the Barometer Group, Mr. Moul relied on data from *Value Line Investment Survey* to determine that the average beta for the Barometer Group is 0.68 (Exh. KEDNE/PRM-2, Schedule 10, at 1). However, this beta must be adjusted to be reflective of the financial risk associated with the rate making capital structure that is measured at book value. As a result, Value Line betas have been adjusted to 0.81 for the Barometer Group by using a formula that "unleverages" the Value Line betas and "releverages" them for the common equity ratios using book values instead of market values (id. at 48).

To determine the market risk premium, Mr. Moul averaged the historical market performance of 7.0 percent with the Value Line forecast of 12.68 percent, resulting in a market premium of 9.84 percent (7.0% + 12.68% = 19.68%/2) (id. at 49). Using the 5.25 percent risk-free rate of return, the leverage adjusted beta of 0.81 for the Barometer

Group, and the 9.84 percent market premium, the following return on equity is derived based on the CAPM model:

$$
\begin{array}{lcccl}
Rf & + & \beta & (Rm\text{-}Rf) & = k \\
5.25\% & + & 0.81 & (9.84\%) & = 13.22\%
\end{array}
$$

The CAPM result is for the Barometer Group. However, as the size of a firm decreases, its risk (and associated required return) increases. The Barometer Group has an average market capitalization of its equity of $1,087 million, which would place it in the sixth decile according to the size of the companies traded on the NYSE, AMEX and NASDAQ (id. at 50). Accordingly, the Barometer Group must be viewed as a portfolio of low-cap companies consisting of those in the 6^{th} through 8^{th} deciles with market capitalization between $269 million and $1,115 million. This would indicate a size premium of 1.42 percent, increasing the CAPM result from 13.22 percent to 14.64 percent. Absent such an adjustment, the CAPM would understate the required return (id.).

The Attorney General charges that Mr. Moul's CAPM model fails to address many of the shortcomings in the methodology previously identified by the Department (Attorney General Initial Brief at 85-88). The Attorney General also maintains that Mr. Moul's application of the CAPM analysis is flawed because he assumes that all investors have a 20-year-or-greater investment horizon (id. at 88). According to the Attorney General, if one assumes that investors had a 30-day investment horizon, their CAPM required return on equity would be 8.30 percent. The Attorney General's arguments are without merit.

As described by Mr. Moul, the CAPM attempts to describe the way prices of individual securities are determined in efficient markets where information is freely available and is reflected instantaneously in security prices (Exh. KEDNE/PRM-3, at H1). This "efficient market hypothesis" underlies both the DCF and CAPM models and arguably could be used to challenge either of these models. Notably, the Attorney General is not deterred from advocating the use of the DCF model despite such arguable assumptions. However, all measures of the cost of equity include restrictive assumptions that may not conform with the so-called "real-world." This charge, standing alone, does not diminish serious scholarly efforts to overcome such challenges over time.

The Attorney General is incorrect that Mr. Moul used the yield on 20-year Treasury bonds as the measure of the risk-free rate of return. To the contrary, Mr. Moul used the yield on the broad spectrum of Treasury Notes and Bonds (Exh. KEDNE/PRM-1, at 48-49, Exh. KEDNE/PRM-2, at 21 and Exh. KEDNE/PRM-3, at F-10, F-11). The Attorney General's reliance on a 30-day investment horizon is misplaced and inconsistent with the CAPM.

> First, rates should be set on the basis of financial conditions that will exist during the effective period of the proposed rates. Second, 91-day Treasury bill yields are more volatile than longer-term yields and are greatly influenced by FOMC monetary policy, political, and economic situations. Moreover, Treasury bill yields have been shown to be empirically inadequate for the CAPM.

Exh. KEDNE/PRM-3, at F-11.

Moreover, the Attorney General's proposed CAPM of 8.30 percent appears in his brief for the first time without reference to any record support for his assumptions. The Attorney General has not shown the basis for his 7.4 percent "Equity Risk Premium" when using five-year Treasury yields. Nor has he provided any record support for the 1.5

percent yield on 30-day Treasury bills.[59] The Department should not permit the Attorney General to generate a CAPM result that is flawed in its assumptions and established without evidentiary support on the record.

8. The Company's Comparable Earnings Approach is Reasonable

The CE approach uses a set of parameters that identify similar risk characteristics of a utility and a group of companies with comparable risk that are not public utilities (Exh. KEDNE/PRM-1, at 51; Exh. KEDNE/PRM-3, Appendix I). Because regulation is a substitute for competitively-determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return (Exh. KEDNE/PRM-1, at 52). This is because the rate of return for a regulated public utility must be competitive with returns available on investments in other enterprises having corresponding risks, especially in a more global economy (id. at 53). To identify the comparable risk companies, the Company selected historical and forecast returns for non-regulated companies from the *Value Line Investment Survey for Windows*, which has six categories of comparability designed to reflect the risk of the Barometer Group.[60] By applying these selection criteria, the Company identified 49 non-utility companies deemed to have comparable risks to the Company (Exh. KEDNE/PRM-2, Schedule 11, at 2). Based on this analysis, the return on equity for non-utility companies

59 The Attorney General's CAPM calculations also contain serious inconsistencies. For example, in his first CAPM calculation, the implied market return is 10.34 percent (2.94% + 7.40%), yet in the second CAPM calculation, the implied market return falls to 9.90 percent (1.50% + 8.40%). There is no factual or record basis for such a change in the market return between these calculations.

60 These six categories are: (1) Timeliness Rank; (2) Safety Ranking; (3) Financial Strength; (4) Price Stability; (5) Value Line betas; and (6) Technical Rank (id. at 53).

comparable to Boston Gas is 13.90 percent, and represents the Comparable Earnings result for this case (Exh. KEDNE/PRM-1,. at 55).

The Attorney General argues that the Company's Comparable Earnings analysis should be rejected because the Department has previously rejected the same approach in other rate cases (Attorney General Initial Brief at 89-90). The fact is that the Department has not rejected the Comparable Earnings methodology, but has criticized its application in specific cases. The methodology is fully consistent with the requirements of the Department. The results of the Company's Comparative Earnings analysis in this case were used as corroborative evidence to show that the 12.18 percent rate of return on common equity, which is based primarily on the DCF and Risk Premium methodologies for the Company, is conservative and reasonable. This rate of return is in stark contrast to the Attorney General's proposal that would lead to a downgrade of the Company's credit quality. The Attorney General's 8.99 percent rate of return on common equity, together with a 59.4 percent debt ratio would produce debt leverage and pre-tax interest coverage clearly in the BBB credit quality rating category (see KEDNE/PRM-1, at 18). Such a downgrade in credit quality would not conform with the mandates of Bluefield and Hope.

9. The Department Should Not Disaggregate the Cost of Common Equity by Customer Class

The Attorney General maintains that the Department should disaggregate the allowed return on common equity to reflect the different investment risk associated with each rate class (Attorney General Initial Brief at 92). According to the Attorney General, the Department should recognize a 100 basis point lower cost of capital for residential customers because residential customers are less likely to participate in fuel switching and therefore provide a more stable base of revenues (id.). The Attorney General's proposal is void of sufficient evidentiary support, violates the Department's longstanding ratemaking policy in favor of equalized rates of return, and reflects an unbalanced assessment of the risk attributable to the residential customer class. Mr. Moul testified that residential customers have a poorer load factor than other classes of customers (Tr. 15, at 1910 [Moul]). As a result, weather conditions (i.e., a cool summer) will have a greater effect on revenues from residential customers than C&I customers with a higher load factor.

Not only does the evidence cited by the Attorney General fail to support his proposal, he has pointed to no Department precedent that would support this proposal made for the first time on brief.[61] If the Attorney General wished to have the Department consider this novel ratemaking proposal in this case, he should have developed a record addressing the proposal and permitted the Company to present relevant information regarding the efficacy and ramifications of the proposal.[62] In the absence of such evidence, the Department cannot seriously consider the Attorney General's proposal in this case.

IV. RATE DESIGN

A. The Company Has Designed Rates In A Manner Consistent with Department Precedent.

The Company has designed rates in a manner consistent with Department

[61] The Attorney General's suggestion is, on its face, inconsistent with the Department's longstanding policy goal of equalizing rates of return among rate classes. Boston Gas Company, D.P.U. 88-67 (1988).

[62] The brief colloquies cited by the Attorney General do not directly address the issue of differing rates of return by class of customer.

precedent. See D.P.U. 96-50 (Phase I) at 133-136; D.P.U. 93-60, at 331-332; D.P.U. 92-78, at 116. First, the Company performed a Cost of Service Study ("COSS") based on the Company's revenue requirements (Exh. KEDNE/AEL-1, at 15). The Company also developed an appropriate marginal cost study ("MCS") in a manner consistent with Department precedent. D.T.E.-01-56, at 122, D.P.U. 96-50 (Phase I) at 150-152; D.P.U. 93-30, at 368-376.[63] In addition, the Company designed its proposed rates in a manner consistent with the Department's goals for utility rate structure: (1) efficiency; (2) simplicity; (3) continuity; (4) fairness; and (5) earnings stability. D.P.U. 96-50 (Phase I) at 133-136; D.P.U. 93-60, at 331-332; D.P.U. 92-78, at 116.

In order to achieve a rate design consistent with the Department's goals, the Company followed five steps. First, the Company performed the COSS to assign revenue and a portion of the Company's total cost of service to each rate class (Exh. KEDNE/AEL-1, at 15; Exh. KEDNE/AEL-5; Exh. KEDNE/ALS-1, at 5). Second, the Company performed the MCS to determine its incremental costs (Exh. KEDNE/ALS-1, at 5; Exh. KEDNE/ALS-2). Third, the Company converted marginal costs into rates for each rate class (Exh. KEDNE/ALS-1, at 5). Fourth, the rates set at marginal costs are reconciled with the revenue requirement for each customer rate class (id.). Fifth, the resulting rate structure was compared to existing rates (id.). Where the Company found that the resulting rate increases are too great for some customers, then it adjusted its rate design to move rates toward marginal costs in a way that is more consistent with the goal

63 Questions were raised during the proceeding regarding the applicability to the Company of the Department's order in D.T.E. 02-24/25 (2002) regarding Fitchburg's future marginal cost studies (Tr. 14, at 1749). As noted by Mr. Silvestrini, the Company interpreted the Department's order in D.T.E. 02-24/25 regarding future marginal cost studies as recommendations for Fitchburg only (id.).

of rate continuity (id.).

The Company has also proposed the adoption of a Weather Stabilization Clause[64] ("WSC") that will stabilize rates for customers during periods of significant weather fluctuations. The Company demonstrated that its WSC is consistent with the Department's goal of providing customers with rate continuity and, thus, should be approved by the Department.

B. The Company's COSS Properly Allocates Company Costs and Revenues to Customer Classes.

The Company presented the testimony of Ms. Leary regarding the Company's COSS (Exh. KEDNE/AEL-1). The COSS analyzed Company-wide costs and revenues and allocated them to the various customer classes based on cost-responsibility principles (Exh. KEDNE/AEL-1, at 16; Exh. KEDNE/AEL-5). Specifically, the COSS determined the cost of serving each rate class, established the revenue requirements by season for each rate class, and identified whether cross-subsidies between rate classes existed (id.). As noted in Ms. Leary's testimony, the COSS was used as the basis for the MCS presented by Mr. Silvestrini and for rate design, which ensures that customers in each rate class are not only charged for their total cost of service, but also are charged the marginal cost of service at each point in time that they may take service (Exh. KEDNE/AEL-1, at 16-17). Where significant differences between the allocated test-year costs and revenues for a given rate class existed, the COSS resolved those differences by allocating the difference among all customer classes to reduce disparities in the rates of return

[64] The Company agreed during evidentiary hearings to revise the name of the clause from "Weather Normalization Clause" to "Weather Stabilization Clause" in order to minimize confusion as it may relate to the process of normalizing rates to account for weather fluctuations in the context of determining base rates (Tr. 4, at 407).

among customer classes (id.).

The Company's COSS is also "time-differentiated" to account for the fact that the Company's loads, costs and revenues vary substantially between the summer and winter months (id.). Because of this variation, the Company determined the rate-class utilization of the Company's services during different time periods (id.).[65] The throughput on the Company's distribution system is substantially higher during the colder peak months than during the off-peak months because of the relatively large proportion of temperature sensitive load being served by the Company (id.). The costs incurred to satisfy demands for throughput levels are appropriately allocated to those rate classes that use the system during the peak period. Accordingly, the Company's rate design process used the same peak and off-peak periods to set rates as is used in the COSS to allocate costs.

The Company's cost allocation process was accomplished in several steps, consistent with Department precedent. See, e.g., Boston Gas Company, D.P.U. 96-50, at 133-134 (1996); see also Exh. AG-8-9. In the first step, costs are "functionalized," or assigned to a group that describes a physical function that the costs are associated with, i.e., local production and storage of gas, transmission and distribution of gas, or other general and administrative purposes (Exh. KEDNE/AEL-1, at 18). In the second step, costs within each functional group are "classified" into one of three categories according to the factor that is causing the cost to be incurred, i.e.: (1) demand or capacity related, which are costs that are incurred to maintain or expand the total capacity of the system to meet projected load in peak periods; (2) energy or commodity related, which are costs that vary depending upon the volume of gas distributed through the system; and

[65] The Company's peak period is from November through April and the off-peak period is from May through October (id. at 18).

(3) customer related, which are costs that vary with the number of customers served (id. at 19). Third, the Company developed allocators to assign costs within each function and each classification to the various customer rate classes in the peak and off-peak period (id.).[66] Lastly, the Company compared the cost of serving each class to the revenues generated by that class in the test year, as well as the Company's overall revenue requirement, to determine whether the class is paying its fair share of the cost of service during each time period (id.) This step was designed to determine the rate adjustment that will ensure that each rate class yields the same rate of return to the Company, or to identify the extent of cross-subsidization if Department precedent dictates that rates of return not be fully equalized among all classes.[67]

The Company provided the Department with detailed testimony and supporting exhibits regarding its COSS methodology (Exh. KEDNE/AEL-21-36; Exhs. KEDNE/AEL-4 through AEL-8).[68] Based on this information, the Company has demonstrated that its COSS properly allocates the Company’s costs and revenues to customer classes, in a manner consistent with Department precedent. Accordingly, the

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66 Ms. Leary’s testimony described in detail the development of the allocators and their application to assign costs within functions and classifications to customer rate classes (Exh. KEDNE/AEL-1, at 22-36; Exh. KEDNE/AEL-5).

67 Ms. Leary also testified regarding the consistency between the allocated COSS analysis presented by Ms. Leary in Exh. KEDNE/AEL-5 and the bundled Cost of Service analysis presented by Mr. McClellan in Exhibit KEDNE/PJM-2, once all gas-related costs, late payment charges, and special contract revenues have been removed (Exh. KEDNE/AEL-1, at 21; Exh. AG-13-1, Exh. AG-13-2). All gas-related costs are now recovered through the Company's CGA (Exh. KEDNE/AEL-1, at 21). Therefore, to design base rates, the Company removed all gas-related costs from the allocated COSS model, including actual gas costs and the associated bad debts, local production and storage costs, and gas acquisition costs (id.; Exh. KEDNE/PJM-2, Exh. NEDNE/AEL-4). Because the allocated COSS model found in Exhibit KEDNE/AEL-5 is used to develop the revenue requirements for firm tariff customers, the Company also removed revenues generated from late payment charges and special contracts (Exh. KEDNE/AEL-2).

68 Additionally, the Company submitted workpapers and other documentation supporting its COSS in response to Exhibits AG-13-6 through AG-13-34.

Department should approve the Company's COSS.

C. The Company's Marginal Cost Study Presented an Accurate Representation of the Company's Marginal Costs and Was Performed Consistent With Department Precedent.

The Company's MCS was developed using the methodology approved by the Department in D.P.U. 96-50, and in the Company's prior rate proceeding, D.P.U. 93-60 (Exh. KEDNE/ALS-1, at 4; Exh. KEDNE/ALS-2; Exh. AG-5-1). As described by Mr. Silvestrini, the MCS was designed to analyze the increased non-gas costs that the Company would incur if it were to expand its services through the addition of distribution capacity, the addition of customers, or the increased throughput of natural gas (Exh. KEDNE/ALS-1, at 4). The combination of the COSS and the MCS allowed the Company to design rates that: (1) collect the Company's revenue requirement in a manner consistent with the costs imposed on the system by individual customer classes; and (2) send accurate price signals to customers to guide their consumption choices (Exh. KEDNE/ALS-1, at 6). The COSS established the total cost of serving each of the Company's existing rate classes, and allowed the Company to identify the total revenues that must be obtained from each of those classes in order to ensure that there is minimal or no cross-subsidization between classes and that parity between the rate classes is maintained. (id.). The MCS was used in conjunction with the COSS to set rates because it identifies the additional cost that would be imposed on the system if new customers, throughput or system capacity were added in the future (id.).

The Company used three different time periods to evaluate incremental costs in the MCS: (1) the design day; (2) the six winter months of November to April; and (3) the six summer months of May to October (id.). The design day was used to measure peaking capacity costs because the Company's planners utilize the design day as the primary planning criterion for decisions concerning production and distribution capacity (id. at 7). Mr. Silvestrini testified that, because space heating is the end-use that places the greatest demand on the Company's distribution system, the winter-heating season is the period when gas-distribution loads increase and weather conditions provide the impetus for demand and, thus, was an appropriate time period to evaluate incremental costs (id. at 7). He further testified that the summer season represents the period of the year when temperatures and gas distribution sales and sendout reflect usage that is primarily "baseload" in nature and thus is an appropriate time period to evaluate cost causation on the Company's system (id.). For the MCS, the Company chose the seasonal periods that coincide with those reflected in the COSS, the Company's current base rates, and the Cost of Gas Adjustment ("CGA") factor (id.).

Mr. Silvestrini developed marginal costs for: (1) distribution system capacity expenses; (2) customer capacity-related expenses, and (3) customer-related operation and maintenance expenses (Exh. KEDNE/ALS-1, at 8-16; Exh. KEDNE/ALS-2; Tr. 4, at 424). With regard to distribution system capacity costs, the Company developed marginal distribution capacity costs for investments in the Company's distribution system (Exh. KEDNE/ALS-1, at 8; Exh. KEDNE/ALS-2, Schedules 1 and 8; Tr. 4, at 428). For this exercise, the Company used the prospective additions method approved by the Department to estimate the marginal costs of reinforcing the existing system to meet expected future growth (based on costs covering the most recent four year period) (id.; Tr. 4, at 427-429; see also D.P.U. 96-50, at 150-151, and D.P.U. 93-60, at 375-376). In addition, Mr. Silvestrini provided detailed testimony and supporting exhibits regarding the development of marginal customer-capacity related costs (Exh. KEDNE/ALS-1, at 10; Exh. KEDNE/ALS-2, Schedule 2; Tr. 4, at 430-435) and capacity-related production expenses (Exh. KEDNE/ALS-3; Tr. 4, at 436-438).

With regard to marginal customer-related operating expenses, Mr. Silvestrini developed such costs by analyzing: (1) transmission and distribution-system expenses, (the maintenance of services and meters); (2) customer-related accounting and marketing expenses; and (3) uncollectible accounts (Exh. KEDNE/ALS-1, at 13; Exh. KEDNE/ALS-2, Schedules 4, 5 and 9; Tr. 4, at 439-440). In order to derive customer-related distribution system expenses, the Company converted annual customer-related service and meter expenses to 2002 dollars using the GDP-IPD (Exh. KEDNE/ALS-1, at 13; Exh. KEDNE/ALS-2, Schedules 4 and 5). Mr. Silvestrini converted the total Company average cost per customer by rate class using the customer costs assigned in the COSS ((Exh. KEDNE/ALS-1, at 13; Exh. KEDNE/ALS-2, Schedule 5). The customer-related accounting, marketing and uncollectible account expenses were derived by Mr. Silvestrini using time-series regression analyses (Exh. KEDNE/ALS-1, at 14; Exh. KEDNE/ALS-2, Schedule 5).

To further develop the Company's marginal costs, Mr. Silvestrini also derived loading factors which reflect administrative and other indirect expenses that will increase proportionally with increases in direct labor expenses or plant investment costs ((Exh. KEDNE/ALS-1, at 15; Exh. KEDNE/ALS-2, Schedule 6; Tr. 4 at 443-444). Mr. Silvestrini also derived fixed charge rates associated with the Company's amortization of large, one-time investments in distribution plant, services and meters in order to derive an annual revenue requirement for determining marginal costs (Exh. KEDNE/ALS-1, at 16;

Exh. KEDNE/ALS-2, Schedule 7; Tr. 4, at 444). Consistent with the methodology used by the Company in D.P.U. 96-50, the Company chose an escalating "economist's" rate because it more closely represents the actual useful lives of the Company's fixed assets ((Exh. KEDNE/ALS-1, at 17). The Company's MCS is summarized in Exh. KEDNE/ALS-2, Schedules 8 through 11 (Tr. 4, at 445-453; see also Exh. AG-29-3; Exh AG-29-4). The results of the MCS were used to establish the tailblock rates for each season for each rate class, in order to give customers the proper price signal to determine their level of consumption of gas in a given season (Exh. KEDNE-ALS-1, at 20).

Pursuant to a request by the Department, Mr. Silvestrini attempted to re-model the Company's MCS using new regression analyses, specifically, a replication of a regression analysis that was presented in a study titled Marginal Cost Pricing For Gas Distribution Utilities: Preliminary Analysis and Models (dated 1980) (Tr. 14, at 1761; RR-DTE-55). Mr. Silvestrini testified that the results of the remodeled MCS are not useful for rate design purposes because one of several unacceptable results applied to each of the equations used in the remodeled MCS.[69]

Accordingly, the Department should find that the Company's MCS accurately represents the Company's marginal costs and was derived in a manner consistent with Department precedent.

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69 Such unacceptable results included: (1) negative marginal costs estimates; (2) poor statistical results; (3) inconsistent results; (4) estimates too high to be considered for rate design; and (5) results too inconsistent between the class estimates for marginal costs to be useful for rate design (RR-DTE-55; Tr. 24, at 3279).

D. The Company Designed Rates in a Manner Consistent with the Department's Rate Design Goals

Mr. Silvestrini presented detailed information regarding the Company's proposed rate design (Exh. KEDNE/ALS-1, at 20-31; Exh. KEDNE/ALS-3 (revised); Exh. KEDNE/ALS-4 (revised); Exh. KEDNE/ALS-5 (revised); Exh. KEDNE/ALS-7 (revised)). The Company designed rates to be consistent with the Department's rate-structure goals of fairness, efficiency, simplicity, continuity,[70] and earnings stability, the Company proposed to phase in cost-based customer charges to reduce intra-class subsidies (Exh. KEDNE/ALS-1, at 20). Mr. Silvestrini and Ms. Leary's testimony demonstrated that none of the customer classes are currently paying their full embedded-cost customer charges, as evidenced by the fact that all classes are recovering a portion of their allocated customer costs in headblock rates, which violates the Department's goals of economic efficiency and fairness. (id., see also Exhs. KEDNE/AEL-5 and AEL-6).

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70 The Company's efforts to address rate continuity considerations are evidenced by: (1) the Company's decision to increase the current customer charge by only one-third of the difference between the fully allocated embedded customer charge and the current customer charge; (2) for the R-3 rate class, shifting approximately $14 million from the off-peak revenue requirement to the peak revenue requirement to ensure that the peak period headblock rate was not less than the off-peak headblock rate; and (3) shifting $500,000 from the G-54 rate class to the G-53 rate class and $300,000 from the G-54 rate class to the G-43 rate class to ensure that: (a) rates for non-heating classes were lower than for heating classes; and that (b) rates for classes with larger customers were lower than for those with smaller customers (Exh. AG-23-20).

The Company is also committed to implementing a 10 percent cap on rate increases for residential customers during the first year of the Rate Plan (Tr. 3, at 373; Exh. MDFA-1-7). The Company will also implement a cap on increases to other classes of customers if the Department believes that such a cap appropriately balances the goals of rate continuity and fairness (Exh. AG-23-23 (supp)). However, the Company's rate design allocates costs for the entire rate class, which includes costs related to the class's load factor (Tr. 3 at 325). Therefore, as testified to by Mr. Silvestrini, in certain instances, the proposed rate increase for some customers with low load factors (i.e., certain large commercial or industrial customers) may be more than for other customers with higher load factors (id. at 326). Accordingly, although some customers with low load factors may experience a greater increase in rates than customers higher load factors, such a result is consistent with rate design principles of cost causation and rate fairness (see id.).

Accordingly, to the extent possible, the Company set the standard tariff tailblocks at the long-run marginal cost, as determined by the MCS (Exh. KEDNE/ALS-1, at 20). Moreover, Mr. Silvestrini testified that, because a single-step volumetric charge is simpler for customers to understand and is easier to administer, the Company established single-step rates where possible (id. at 21).[71] Further, Mr. Silvestrini testified that, to promote efficiency, the Company set the peak period tailblock rate at the marginal distribution cost (id.).

Consistent with Department precedent, the Company generally set the break between headblock and tailblock rates at a level that results in approximately 50% of customer bills terminating in the headblock and 50% in the tailblock (id.; see also D.P.U. 96-50 (Phase I) at 152-153). In order to enhance the Department's goal of earnings stability, the Company set the off-peak tailblocks at levels that will ensure that a level of margin will be collected in the off-peak period (Exh. KEDNE/ALS-1, at 21). In addition, the Company's rate design proposal allocates social subsidies created by the discount rates across the broadest base of core classes (id.).[72]

The Company also made changes in the way that gas-supply related costs are unbundled from distribution service rates (Tr. 3, at 291). In the Company's last rate case, D.P.U. 96-50, the Department found that recovery of costs associated with local

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[71] Mr. Silvestrini noted, however, that, where customer costs are not fully recovered in the customer charge (as is the case with the Company's residential rates), the second best solution is to create a headblock or volumetric charge in a consumption block that does not distort the price signal of the tailblock (Exh. KEDNE/ALS-1, at 21). Accordingly, the Company is proposing a tailblock rate and a headblock rate for the residential classes to recover the revenue requirement for those classes (Exh. AG-29-7; Exh. AG-29-8).

[72] The recovery of DSM costs and manufactured gas remediation costs will continue to be recovered through the Local Distribution Adjustment Charge, which is billed to all core throughput customers (Exh. KEDNE/ALS-1, at 21).

production and storage facilities should be allocated between base rates and the CGA, using a percentage split of 15% to base rates and 85% to the CGA, in order to insure that transportation-only customers had responsibilities for their share of local production and storage costs necessary to maintain system reliability (Exh. KEDNE/ALS-1, at 22; see also D.P.U. 96-50 (Phase I) at 150). However, because those facilities are no longer used to support distribution-system integrity, the Company allocated 100% of production and storage costs to the CGA (id.).[73] Accordingly, the Company presented an unbundled cost allocation study to determine the revenue requirement associated with these facilities and deducted this amount from the total revenue requirement to be billed through base rates (Exh. KEDNE/ALS-1, at 22; Exh. KEDNE/AEL-6; Exh. KEDNE/ALS-7 (revised); Exh. AG-29-10; Tr. 3, at 291-293).[74]

Mr. Silvestrini presented detailed information regarding the Company's specific rate design decisions in Exh. KEDNE/ALS-1, at 23-31. Accordingly, the Company designed its rates in a manner consistent with the Department's rate design goals and such rates should be approved by the Department.

[73] To accomplish this change, the Company conducted an unbundled cost-allocation study to determine the revenue requirement that is associated with these facilities (Exh. KEDNE/ALS-1, at 22; see also Exh. KEDNE/ALS-7). This amount has been deducted from the total revenue requirement to be billed through base rates and will be included in the CGA calculation (Exh. KEDNE/ALS-1, at 22).

[74] The Company demonstrated specific adjustments to its CGA and base rates in response to Exhs. AG-13-29 through AG-13-38 and Exhs. AG-23-3 through 23-6, 23-9 and 23-11.

V. PERFORMANCE-BASED RATE PLAN

A. The Company's Proposed Performance Based Rate Plan Is Consistent With Department Precedent and Should Be Approved for Implementation

1. Description of the Plan

The record demonstrates that the Company has proposed a well-balanced PBR Plan that is consistent with the Department's directives in D.P.U. 96-50 and comports with sound regulatory and economic policy. In proposing this PBR Plan, the Company's objective is to put in place a ratemaking mechanism that provides the Company with the incentive and opportunity to manage costs and increase productivity so that the need for a base-rate proceeding may again be avoided for a prolonged period of time (Exh. DTE-6-4).

As proposed, the PBR Plan would commence on November 1, 2003 to coincide with the date that the cast-off rates resulting from this proceeding will go into effect. The PBR Plan is intended to be implemented over a five-year period of time with annual compliance filings that will be designed to set the rates for effect on November 1 of each year beginning in 2004, and ending with the last rate adjustment on November 1, 2008 (Exh. KEDNE/JFB-1, at 5). As stated on the record in this proceeding, the five-year term of the PBR Plan strikes a balance between creating incentives and reflecting recent trends within the gas industry concerning pricing and growth (id.). If the time between plan review is too long, there is a possibility that the data used to set the terms of the plan will become "stale" and no longer reflect current conditions (id.; Exh. DTE 6-11). The Company's PBR Plan, therefore, is designed to be long enough to create meaningful incentives, but short enough to reflect current circumstances within the gas marketplace (Exh. DTE-6-11).

The Company is also proposing that the PBR Plan be extended beyond the five-year term, on a year-to-year basis (the "Extended Term"), without further action by the Department, unless an investigation is initiated on its own motion, or at the request of the Company under G.L. c. 164, § 94, or the Attorney General or other entitled persons under G.L. c. 164, § 93 (id.). Commencing on June 1, 2009, and annually thereafter, the Company would notify the Department of its intention to submit a compliance filing each September 15 to extend the term of the PBR plan by an additional year. Unless a base-rate investigation by the Department is initiated pursuant to G.L. c. 164, § 94, the PBR Plan would extend by operation of the Department's approval of the Extended Term compliance filing (id.).

As detailed on the record, extending the PBR Plan beyond the five-year term on a year-to-year basis effectively extends the benefits to customers that are associated with a multi-year rate plan (Exh. DTE-6-10). As proposed, the "year-to-year" extension would involve a pro-forma filing with the Department and not involve a lengthy review of the Company's cost of service or PBR parameters (id.). Such extensions would promote a stable regulatory framework and retain the use of external performance standards in ratemaking (id.).

As stated on the record, the Company's proposal to extend the PBR Plan beyond five years is consistent with the theory of PBR because the regulatory mechanisms that the Company proposes to implement will create stronger performance incentives that will lead to a more efficient provision of utility services and ultimately greater customer benefit. (Exh. DTE-6-10). Stronger incentives are created by external performance standards (i.e., rates are tied to industry performance measures whereby the utility is effectively competing to keep its unit costs below those of the industry and, if successful, is allowed to retain at least part of the gains) (Exh. DTE-6-10).

Under the PBR Plan, the Company would adjust prices annually up to a cap measured by a predetermined formula, that could be adjusted further to account for changes in tax laws, accounting principles, and regulatory, judicial or legislative actions that uniquely affect the local gas distribution industry (Exh. KEDNE/JFB, at 26). In addition, the Company would have the opportunity to propose exogenous changes to the Department in circumstances where it can be demonstrated that the factor driving the cost change is beyond the Company's control and that the cost change is not reflected in the Gross Domestic Product – Price Index. (id.).

As described in below, an essential element of the PBR Plan is the establishment of just and reasonable cast off rates that will enable the Company to provide quality and reliable service over the term of the PBR Plan. As documented on the record and discussed below, the Company's cast off rates are accurately calculated based on the known and measurable costs incurred by the Company. Once the cast-off rates are determined, the rates would be adjusted in accordance with the price-cap formula.

2. Standard of Review

The Department's standard of review for incentive ratemaking proposals is well established: A petitioner seeking approval of an incentive proposal is required to demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates, and reduced administrative burden in regulation. Boston Gas, D.P.U. 96-50 at pp. 242-243. Incentive Regulation, D.P.U. 94-158 at 57 (1995) (D.P.U. 94-158).

In addition to these general criteria, the Department has also established more specific criteria to be used in evaluating incentive proposals. Id. These criteria require that incentive proposals:

> (1) must comply with Department regulations, unless accompanied by a request for a specific waiver. The Department added that incentive proposals that comply with statutes and governing precedent are strongly preferred;
>
> (2) should be designed to serve as a vehicle to a more competitive environment and to improve the provision of monopoly services. Incentive proposals should avoid the cross-subsidization of competitive services by revenues derived from the provision of monopoly services;
>
> (3) may not result in reductions in safety, service reliability or existing standards of customer service;
>
> (4) must not focus excessively on cost recovery issues. If a proposal addresses a specific cost recovery issue, its proponent must demonstrate that these costs are exogenous to the company's operation;
>
> (5) should focus on comprehensive results. In general, broad-based proposals should satisfy this criterion more effectively than narrowly-targeted proposals;
>
> (6) should be designed to achieve specific, measurable results. Proposals should identify, where appropriate, measurable performance indicators and targets that are not unduly subject to miscalculation or manipulation; and
>
> (7) should provide a more efficient regulatory approach, thus reducing regulatory and administrative costs. Proposals should present a timetable for program implementation and specify milestones and a program tracking and evaluation method.

Boston Gas, D.P.U. 96-50 at 243-245; Incentive Regulation at 58-64. As demonstrated in the testimony of the Company's nationally recognized independent expert, Dr. Kaufmann, the Company's PBR Plan is squarely consistent with each of these criteria.

3. Productivity Offset

The Company's proposed productivity offset, X, is made up of three components that serve as an adjustment to the Gross Domestic Product Price Index ("GDP-PI"): (1) a productivity differential; (2) an inflation differential; and (3) a consumer dividend (Exh. KEDNE-LRK-1, at 1-2). Based on empirical research, the Company proposes an overall X factor no greater than –0.2 percent (id. at 2). This figure is comprised of a minus 0.45 percent productivity differential, a 0.1 percent inflation differential, and a consumer dividend of 0.15 percent.

The X factor is defined by the following formula, which is explained immediately below:

$$X = (TFP^{IND} - TFP^{US}) + (W^{US} - W^{IND}) + CD$$

Exh. KEDNE/LRK-1, at 3. In this formula, the total factor productivity ("TFP") is a ratio (also known as an "index") of a given product's output quantity index to its input quantity index (id. at 7). The output quantity index of an industry summarizes the amount of work that it performs. An industry's input quantity index summarizes the amount of production inputs it has used to perform this work (id.). The overall ratio identifies the "productivity" of the industry. For example, TFP growth can occur as a result of technological developments that permit an industry to produce a given output quantity with fewer input quantities. Economies of scale are a second source of TFP growth that occur when costs grow less rapidly than output, so that unit costs decline when output expands (id. at 8). The difference ($TFP^{IND} - TFP^{US}$) is referred to as the productivity differential, and represents the difference between the productivity of a particular industry (i.e., the gas distribution industry) and the productivity of the entire US economy.

The difference (W^{US} - W^{IND}) is referred to as the inflation differential. W^{IND} is the input price trend for the gas distribution industry and W^{US} is the input price trend for the US economy (id. at 3). The growth rate of input prices for a particular industry (i.e., the gas distribution industry) was computed as a weighted average of the growth rates in price subindexes for capital services, labor and non-labor O&M inputs (id. at 12). The weights were based on the shares of these inputs in the industry's total cost of gas distribution (id.).

As stated above, the Company's proposed consumer dividend ("CD") in this case is 0.15 percent. In theory, consumer dividends are designed to reflect productivity gains that occur as a result of stronger performance incentives created after a PBR plan is implemented (id. at 6). However, it is important to recognize that companies such as Boston Gas Company, that are relatively good cost performers at the beginning of a PBR plan will have less "fat" to cut and therefore less opportunity to improve its productivity performance.

The first two adjustments to the GDP-PI, (TFP^{IND} - TFP^{US}) and (W^{US} - W^{IND}), are made because the GDP-PI is a measure of change in output prices in the whole economy. Changes in output prices are the result of changes in input prices (W) and changes in productivity (TFP) (id.). Therefore the GDP-PI must be adjusted to account for those changes in input prices for the gas distribution industry or productivity changes for the gas distribution industry that are different from these same factors for the overall US economy (id.).

⇨ Total Factor Productivity

Because TFP is defined as the ratio of a given product's output quantity index (a quantitative measure of output) to its input quantity index (a quantitative measure of input), the Company, through the consulting group of Pacific Economics Group, LLC ("PEG"), performed a study, titled "X-Factor Calibration for Boston Gas" (the "Productivity Study") that measured the trends in productivity during the years 1990-2000 of the Northeast gas distribution industry, as well as trends in input price indexes for gas distributors and the overall U.S. economy (Exh. KEDNE/LRK-2, at 2).[75] Changes in productivity in the Northeast gas distribution industry are ultimately compared to changes in productivity across the entire U.S. economy.

To analyze the changes in productivity over time in the gas distribution industry, the Company compared the ratio of output quantities to input quantities over a ten-year period. TFP *increases* when the output quantity index rises more rapidly (or falls less rapidly) than the input quantity index (i.e., increased productivity). TFP fluctuates from year to year but in most industries trends upward over time (id. at 8). The gas distribution industry TFP growth was 0.53 percent per annum, compared to the growth of the federal government's multi-factor productivity index for the U.S. private business sector of 0.98 percent over the same period (1990-2000) (id.). The differential between the TFP trends for Northeast gas distributors and the U.S. economy is therefore -0.45 percent.

The growth rate in the output quantity index is a weighted average of the growth rates in two sub-indexes: (1) the number of customers served ; and (2) total gas throughput (id. at 9). The growth rate in each input quantity index was a weighted average of the growth rates in quantity sub-indexes for capital, labor, and non-labor

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[75] Gas distribution was defined to include all gas delivery and customer account and customer information services that gas distributors provide (id. at 3).

operation and maintenance inputs. The relevant costs comprised O&M expenses and the cost of capital (id.).

The best available proxy for the TFP growth of the U.S. economy is the multi-factor productivity ("MFP") index of the U.S. private business sector, as calculated by the U.S. Bureau of Labor Statistics ("BLS"). The MFP index for the U.S. private business sector grew by an average annual rate of 0.98 percent in the 1990-2000 period – nearly twice the rate of productivity growth for the Northeast gas distribution industry during the same period (id. at 10). This productivity differential, which is based on the difference between the growth trends of the two productivity indexes, results in a –0.45 percent TFP adjustment to GDP-PI.

A negative productivity growth factor is neither surprising nor cause for rejection of the resulting TFP adjustment factor. The BLS has produced estimates of productivity growth, over an almost identical period, for 108 U.S. manufacturing industries (id. at 11, citing *Multifactor Productivity Measures for Three-Digit SJC Manufacturing Industries*, 1990-99, U.S. Department of Labor Bureau of Labor Statistics, Report 965, January 2002. As Dr. Kaufmann testified:

> These data show that there was a negative productivity differential between the US economy and 67 of these 108 industries. The largest such productivity differential, for drug manufacturing, was –4.2 percent. TFP evidence for different US industries therefore reveals that the –0.45 percent productivity differential for the gas distribution industry is neither unusual nor especially large relative to many other sectors of the US economy.

Exh. KEDNE/LRK-1, at 11. Notably, the BLS has concluded that the economy's actual productivity trend is likely to be even *greater* than what is reported because, in part, of the difficulty of measuring output in some service sectors. In fact, research performed by the BLS indicates that the actual annual growth in US MFP may be as much as 0.4 percent higher than the BLS estimates (id. at 11-12).

⇨ Inflation Differential

In addition to TFP, the second factor that affects GDP-PI, is the change in input prices, which is known as the Inflation Differential. The growth rate in the input price index for Northeast gas distributors is computed as a weighted average of the growth rates in price sub-indexes for capital services, labor, and non-labor O&M inputs (id. at 12). Because an input price index for the U.S. economy is not available from government sources, the Company constructed the trend in the economy's input prices based on indexing theory, which holds that, to the extent that the economy earns a competitive return, the long-run trend in its input prices is the sum of the trends in its output prices and its TFP. The resulting input prices in the U.S. economy grew at a 3.10 percent average annual rate for the 1990-2000 period (id. at 13). By comparison, the input price index for gas distribution companies averaged 3.02 percent annual growth. Therefore, the input price index for the economy grew 0.1 percent more rapidly, on average, than the input price index for Northeastern gas distribution companies.

⇨ Consumer Dividend

The Department has previously recognized that the Consumer Dividend is intended to reflect "future" productivity gains expected from a regulated company operating on a going forward basis under a PBR plan rather than under a traditional cost of service framework (Exh. KEDNE/JFB-1, at 24). The Department has also recognized that little information exists to quantify the efficiency improvements that "should" result as regulated gas utilities move from cost-of-service to PBR regulation (id.).

Nevertheless, in accordance with the underlying theory that a PBR framework provides a utility with the incentive to achieve efficiency gains that should be shared with customers during the term of the PBR plan, the Company is proposing a Consumer Dividend of 0.15 percent.

The Company's proposed 0.15 percent consumer dividend is reasonable and reflects a realistic assessment of the level of additional efficiencies available for the Company to capture during the period of its second PBR plan (Exh. KEDNE/LRK-1, at 16-17). The consumer dividend in the recently ended PBR plan for the Company was 0.5 percent. As a result of that PBR plan, the Company's reduced its costs by 0.3 percent during the PBR period of 1997-2000 compared with what they would have been in the absence of PBR (id. at 16). In this case, a lower consumer dividend is warranted. First, it likely will become progressively harder to reduce costs now that the Company has realized the most easily achievable and efficient savings under its first PBR plan (id.). Since 1997 the Company implemented a number of efficiency improvements, such as a comprehensive reorganization of its operations as a result of the QUEST reengineering project, that cannot be repeated in the second term of PBR. In 2000, the Company became part of KeySpan, consolidating operations and streamlining its organization. The savings attributable to these reductions are now already reflected in the Company's test year O&M expense levels.

Second, Dr. Kaufmann testified that regardless of whether the Company has been operating under PBR in the past, the Company is already a highly efficient cost performer, with relatively little additional "fat" to cut (id.). Third, there are significant factors outside of the Company's control that may overwhelm the ability of the Company to achieve efficiencies.

B. DOER Proposal

In its initial brief, the Division of Energy Resources ("DOER") recommended: (1) recommended general policy changes by the Department with respect to its review of PBR plans; and (2) specific changes to the Company's PBR plan. DOER proposed an "alternative" PBR formulation, which according to DOER is designed to: (1) be consistent with Department precedent; (2) be consistent with market-based regulation; (3) safeguard system reliability; (4) reward utility performance and addresses exogenous costs; (5) focus on comprehensive results; (6) incorporate measurable indicators of performance; and (7) is consistent with accounting standards (id. at 19-22).

⇨ DOER's Proposed Formula

$PCI_t/PCI_{t-1} = (P_t/P_{t-1}) - X + Z_t$

⇒ Where P_t is the inflation factor as indicated by the Producer Price Index (PCU4981 #26) for U.S. natural gas utilities (transportation only) produced by the Bureau of Labor Statistics;

⇒ X is the X factor given by the following formula:

- $X = (TFP^{BG} - TFP^{IND})$ where TFP^{BG} is the total factor productivity trend for Boston Gas and TFP^{IND} is total factor productivity trend for the gas distribution industry; and

⇒ Z_t is the Z-factor (id. at 22).

DOER contends that the above formula is consistent with the Department's incentive-based ratemaking goals and the data provided by the Company regarding Boston Gas' productivity relative to its peer companies (id.). DOER also contendsthat the formula is simpler than the Company's proposal because it removes a number of "irrelevant" elements from the existing PBR formula, namely:

- TFP for the United States is no longer needed because the comparison of Boston Gas' productivity to the peer group provides a more relevant analysis of the Company's performance;
- input price trend for the gas distribution industry is no longer needed because the Producer Price Index for U.S. Natural Gas Companies captures input-price inflation for the gas industry more effectively than the GDP-PI;
- input price trend for the U.S. economy is no longer needed for the same reasoning as the input price trend for the gas distribution industry; and
- the Consumer Dividend is no longer needed because the productivity comparison accounts for the differential productivity expectations for the Company (id. at 23).

DOER elaborated on its recommendation to eliminate the Consumer Dividend. DOER stated that its supports its elimination because: (1) it is difficult to calculate with any certainty; (2) the theoretical and methodological basis for its calculation is "tenuous"; and (3) the Company's Rate Plan does not allow for firms that are in need of capital for productivity-enhancing investments (id. at 23-24).[76] DOER acknowledged that the Company has been a relatively good cost performer over the 1993-2000 period and that it will be "difficult for the Company to equal or exceed the productivity gains that were alleged to have happened due to the first PBR plan" (id. at 24). The agency contended, however, that the Company has not been able to capture productivity gains over the PBR period, and has "room" to improve its productivity (id.). In contrast to the Company's proposal which may produce a high value for its Consumer Dividend, the agency contended that such result would "prohibit productivity increases in those cases where

[76] The agency noted that, under its alternative proposal, the benefit of the Consumer Dividend is incorporated within the productivity factor (DOER at 24).

productivity can only be increased through additional investment rather than simply cutting of costs" (id.). DOER stated that its alternative formula has resulted in large productivity gains, "especially in the British electricity industry" (id. at 25).

⇨ Inflation Index

DOER also requested that the Company change its PBR formula by using the Producer Price Index for U.S. Natural Gas ("PPI-NG") utilities as an inflation factor, rather than the GDP-PI (id. at 27). Although DOER acknowledged that the Department has previously approved the use of the GDP-PI as an inflation factor, DOER argues that its alternative proposal should be adopted primarily because the PPI-NG, although more volatile than the GDP-PI, is more indicative of the costs facing the natural gas industry (id. at 28).

⇨ Exogenous Factors

DOER requests that the Department require Boston Gas to limit the exogenous factors to "precisely what was approved in D.P.U. 96-50 (Phase I) and subsequently carried forward in proceedings up through an including [D.T.E. 01-56, at 25]" (id.). DOER also contends that the Department should require the threshold for exogenous cost recovery to be proportional to the Company's operating revenues, rather than at the $500,000 per event figure proposed by the Company (id.).

⇨ Earnings Sharing Mechanism/Clawback Provisions

DOER opposed the Company's proposed earnings sharing mechanism ("ESM") alleging that it provided little or no incentive for the Company to improve productivity (DOER at 30). DOER also recommended that the Department consider requiring the Company to implement a "clawback" mechanism whereby any returns gained in excess of a proscribed level during the term of the PBR plan, such as the authorized return on equity, be returned to ratepayers in the event that the Company does not show productivity enhancement during the PBR period (id.). The agency recommended that this adjustment be implemented by comparing the Company's average annual five-year productivity change (over the life of the Rate Plan) to a benchmark of the average annual five-year productivity change over the five year period for the Northeast peer group (id. at 31). Specifically, the DOER suggested that if the performance of the Company is within one standard deviation of the benchmark, as measured by the five year, weighted average ROE, no revenues in excess of the authorized rate of return are returned to ratepayers (id.). If the Company's performance is one standard deviation below the benchmark, then the Company must return any revenues in excess of the authorized rate of return (id.). However, if the Company's performance is greater than one standard deviation above the benchmark, the Company shares the gains above the authorized rate of return with 25% returning to ratepayers (id.).

⇨ PBR Term

DOER recommended that the Department approve the Plan for an initial five year term and then review and determine after the end of the initial term whether the Plan should continue to ensure just and reasonable rates (id. at 32).

C. Attorney General

The Attorney General contends that the Department should reject the Company's PBR proposal as contrary to the Department's goals for incentive rate proposals. The Attorney General's conclusion is based on his allegations that the Company's productivity study was: (1) "unduly complex" (Attorney General at 109); (2) "flawed" (id. at 110); and (3) "unreviewable" (id. at 111).

The Attorney General's general issues focused on his conclusion that the Company's PBR plan is not a traditional PBR, but rather a "hybrid" between a cost of service model and an incentive model, as evidenced by high cast off rates that would increase automatically for years under an inflation-plus PBR formula (id. at 108).

The Attorney General's particular comments focus on the Company's productivity and econometric studies. With regard to the productivity study, the Attorney General contended that the Company's proposed "X Factor," which would increase gas delivery rates at a rate of 0.2% more than the general inflation rate, was unsupported by Dr. Kaufmann's productivity study (id. at 109). The Attorney General specifically took issue with the study's estimates of productivity factors for 16 gas utilities in the Northeast (id.). The Attorney General contended that Dr. Kaufmann: (1) did not adequately justify limiting his analysis to 16 large northeastern gas distribution companies; (2) used inaccurate data; and (3) did not correspond the study "perfectly" to the business cycle (id. at 110-111). The Attorney General stated that the Company's use of inaccurate data results in the "largest single problem" with the productivity study, i.e., its estimation of capital costs (id. at 111).

With regard to the econometric study, the Attorney General alleged that it was based on an "unreviewable" model that, because of flawed study design and cost measurement, does not prove that Boston Gas is an efficient performer (id. at 111-112). He alleged that the study is flawed because it failed to include a "number of variables" that "probably influence cost" (id. at 112). The Attorney General cited testimony by Ms.

Smith to support his further contention that the study includes "numerous problems with capital cost estimation, most of which would tend to bias the study in a direction that would appear to make Boston Gas appear to be low cost when it was not" (id. at 112). The Attorney General also claims the cost study had the same capital measurement "problem" as the productivity study, i.e., it makes Boston Gas appear to be a low cost utility because the value of its old mains is understated (id.). The Attorney General countered that perception by noting that, relative to its capital plant cost, Boston Gas pays a much lower amount of taxes than most of the utilities in the northeast, which distorts the Company's capital cost analysis (id.).

The Attorney General also took issue with claims by Dr. Kaufmann and Company witnesses that the Company will likely not increase efficiency substantially over the next few years by concluding that such claims are inconsistent with the rationale for a PBR plan (id. at 112-113). The Attorney General contended that the Department should allow a PBR for the Company only if is reviewable and not unduly complex (id. at 114). The attorney General also stated that a PBR should have: (1) at least at 1% consumer dividend to allow customers to share some of the savings benefit; and (2) an earnings sharing plan where customers benefit; and (3) an appropriate exogenous change factor that reflects cost reductions as well as increases (but not the Company's new "formulaic capital replacement provision") (id.). The Attorney General also stated that a PBR plan should not be used with the Company's proposed pension reconciliation adjustment mechanism because it "would double-count cost changes" (id. at 114). The Attorney General recommended in closing that the PBR should adjust for savings at the end of the Colonial and Essex rate freezes, perhaps by removing "the inflated value of costs reallocated back to Boston Gas" (id.).

D. Response to the Attorney General and DOER

The Company will not respond to all of the issues raised by the DOER and Attorney General in this initial brief and will address remaining issues in reply. However, there are a number of points that the Company would like to address:

1. **DOER Claim**: The Company did not enjoy lower costs as a result of PBR because it experienced declining TFP over the 1990-2001 Period.

As an initial matter, DOER's analysis is incomplete and the figures it cites are misleading. This is demonstrated by an examination of all the information that PEG provided to DOER on the Table presented in the DOER brief. DOER presents only a single column from this Table in its brief; the full Table is presented below.

Total Factor Productivity
Boston Gas

	TFP Index	Output Quantity Index	Input Quantity Index
1990	1.000	1.000	1.000
1991	0.938	0.960	1.024
1992	0.940	0.992	1.055
1993	0.942	1.021	1.084
1994	0.931	1.027	1.103
1995	0.924	1.028	1.113
1996	0.946	1.058	1.119
1997	0.954	1.079	1.131
1998	0.973	1.050	1.079
1999	0.928	1.026	1.105
2000	0.805	1.022	1.270
2001	0.911	1.033	1.135
Average Annual Growth Rate			
1990-2001	-0.85%	0.30%	1.15%
1990-96	-0.93%	0.94%	1.87%
1997-01	-0.76%	-0.48%	0.28%

This table is identical to the table provided to DOER in response to DOER-RR-1 except for the final two rows. These two rows break down the Company's TFP experience before and after PBR and there are substantial differences in TFP after PBR was implemented. Although it is true that TFP declined while PBR was in effect, the rate of decline (0.76%) per annum was less than the average annual rate of decline prior to PBR (0.93%). More importantly, it is clear that the reason for this decline is the Company's output growth fell dramatically under PBR. The output quantity index changed from a positive growth trend of 0.94% on average before PBR to –0.48% on average during the PBR years, a turn-around of -1.42%.

If the Company's input growth trend had not changed under PBR, this decline in output would therefore have caused TFP growth to fall by an additional –1.42% per year (since the previous TFP trend was –0.93%, this implies that TFP would have declined by 2.35% on average under PBR without changes in input quantity growth). The fact that the Company was able to *improve* its TFP performance under PBR, relative to its TFP trend prior to PBR, is only because Boston Gas cut its input quantity by more than the decline in its output. Input quantity growth fell from an average of 1.87% per annum from 1990-96 to 0.28% per annum during the PBR years, a turnaround of -1.59% per annum. This more than offset the decline in output that occurred during the PBR years and allowed the Company's TFP experience to improve under PBR, compared with the years prior to PBR. In fact, if output had continued to grow at the same 0.94% per annum rate under PBR as it did in 1990-96, the Company would have registered a sharp turnaround in its TFP growth under PBR. All else equal, this rate of output growth would have led to TFP growth for the Company of 0.66% per annum (*i.e.* 0.94% - 0.28% =

0.66%) compared with –0.93% prior to PBR; a 0.66% TFP growth trend for Boston Gas would also have outstripped the TFP growth trend for the regional gas distribution industry (about 0.55% per annum).

Output quantity growth is a weighted average of the growth in number of customers and in delivery volumes; both of these outputs are almost totally beyond the control of Boston Gas. In contrast, the Company has much greater control on its use of inputs. The data show clearly that Boston Gas decreased its input quantity growth substantially when it became subject to PBR and thereby reduced the costs of its operations.

This conclusion is not undermined by the labor-input analysis as suggested by DOER before and after PBR (DOER 15-16). Again, this is an incomplete and misleading focus, since it ignores the fact that other operation and maintenance (O&M) inputs declined by a total of 34% during the PBR years, equivalent to an average annual decline of 6.9%. In addition, the 15% increase in Boston Gas's input quantity index in 2000 does not reflect an "investment strategy" but is due entirely to the transitory costs associated with the Keyspan merger; these costs were not present in 2001, and the Company's input quantity index declined accordingly.

Therefore, far from supporting DOER's contention that PBR was ineffective, a full examination of Boston Gas's TFP data provide further evidence that PBR was successful in spurring productivity improvements, and costs were therefore lower than they would have been in the absence of PBR. This evidence complements, rather than contradicts the evidence developed in the econometric cost model that PBR led to improvements in the Company's cost performance. This evidence also supports, rather than weakens, the conclusion that the PBR plan meets the Department's standards for review of PBR proposals.

Fundamentally, DOER reaches an incorrect conclusion regarding the impact of PBR on the Company's cost performance for two reasons. First, the use of the data provided to them is selective and incomplete, and DOER only highlights data series that, in isolation, support the view that the Company's performance did not improve under PBR. Second, DOER does not attempt to control for factors beyond management control that could affect the company's cost and TFP performance. One such factor noted above was output growth, which declined dramatically during the PBR years and was primarily responsible for the negative TFP growth registered under PBR. However, because output growth is largely beyond management control, this does not imply that the company has become less efficient under PBR (and under the DOER proposal, would be penalized as a result). PEG's econometric model deals with this and other cost influences in a rigorous way. In doing so, the PBR dummy included in the PEG model is the best way to isolate the impact of PBR on the company's cost performance, and the estimated –0.3% for this parameter represents the best available evidence on the extent to which PBR, in isolation, impacted the Company's average annual cost performance. A close look at the Company's TFP experience before and after PBR also supports the conclusion that performance improved as a result of PBR, but such "before and after" comparisons cannot by themselves isolate the cost impact of PBR.

2. **DOER Claim**: Indexing Proposal

There are two aspects of DOER's proposed alternative PBR proposal; the first is an indexing mechanism, where the inflation factor is the producer price index for natural gas utilities (PPI-NG), which DOER claims is a more accurate and reliable index than the GDP-PI for measuring gas utility inflation; and the second is a revised ESM and "clawback" mechanism. Both are highly problematic and the latter, especially, will involve considerable implementation difficulties, will make regulation more rather than less complex, and will increase regulatory burdens

The choice of the PPI-NG is problematic in several respects:

- DOER's index is an output price, not an input price – the inflation measure should measure changes in input prices for the industry, not output prices; as the indexing logic presented in Exhibit KEDNE/LRK-1 shows, the long run trend in an index of industry input prices *exceeds* the industry's long-run trend in an index of its output prices by the amount of the industry's TFP trend; the industry's TFP trend would therefore have to be added to something like the PPI-NG to obtain a decent proxy for industry input prices.
- PPI-NG measures changes in prices for only a single gas distribution service – unbundled distribution charges for transportation-only customers. Therefore it does not reflect output price trends for the total range of services provided by gas distributors, because it does not include the prices charged to sales customers. It is probable that unbundled distribution charges have grown more slowly than distribution charges for smaller-volume sales customers; in many jurisdictions, larger volume customers have historically cross-subsidized smaller customers, and some of these cross-subsidies have been unwound with unbundling. When this is the case, eliminating cross subsidies leads a greater share of common costs to be allocated to smaller customers,

which makes their prices rise more rapidly than for transportation-only customers. However, the BLS does not collect PPI data on the distribution charges for sales customers – PPIs for these customer groups are based on final delivered prices, which include gas commodity charges. There are accordingly no available data to reflect gas distribution prices for all of the services provided by Boston Gas and other distributors, but only for a subset of those services to unbundled transportation customers. Both of these factors imply that the PPI-NG grows more slowly than input price inflation for gas distributors.

- PPI-NG is not available regionally (although PPIs for sales customers, which include gas commodity costs, are available regionally). The Department approved a regional definition of the gas distribution industry in DPU 96-50, and PEG's work confirms that the rationale and results the Dept. used to reach this decision remain true, so a regional definition of the gas distribution industry remains appropriate. Because these data are not available, it would not be possible to select or construct an inflation measure that is appropriate for the gas distribution industry using the PPI-NG.
- PPI-NG data may not even be available going forward, and if they are available they may differ dramatically from historical PPI-NG data. The reason is that beginning in January 2004, the Bureau of Economic Analysis is going to change its basis for industry classification from the 1987 Standard Industrial Classification (SIC) system to the North American Industry Classification System (NAICS). The NAICS was developed in cooperation

with Canada and Mexico and will present a more detailed classification of economic activity in North American economies. Many new NAICS codes will either be created new or will be derived from parts of other SIC codes. There will be considerable changes to the gas distribution classification. The NAICS code for natural gas distribution (22121) will be constructed from all of existing SIC codes 4924 (natural gas distribution), 4925 (mixed, manufactured or liquefied petroleum gas production and/or distribution) and 4932 (gas and other services combined (natural gas distribution)), as well as parts of SIC codes 4823, 4931, and 4939. The NAICS code for natural gas distribution will therefore not be compatible with the previous SIC code for gas distribution.

- The PPI numbers constructed by the Bureau of Labor Statistics will also be revised to be consistent with the new industrial classification system. BLS indicates that it does not currently know how it will transition one set of PPI numbers to the updated classification system, or how long this transition will take. The PPI-NG may not even be measured under the new system. Even if it is, there is a high probability that it will not be consistent with the past PPI-NG series. Changes in the definition of inflation series during the term of a PBR plan clearly add volatility and risk to the plan. In general, the uncertainty associated with this and other PPI series is another factor arguing against their adoption in PBR.
- The current PPI-NG data are themselves somewhat suspect. Most prominently, the PPI-NG in 1998 fell by 5.45% from the previous year. It is

unclear why unbundled gas distribution rates would have fallen so dramatically that year. It is also unlikely that this corresponds to a reduction in gas distribution input prices in that year. For example, PEG calculated that input prices for Northeast gas distributors rose by 0.1% in 1998. Together with the fact that this index is not even measuring input prices, reflects prices for only a subset of gas distribution services and is not available regionally, the PPI-NG data themselves cast doubt on the claim that this index "is a more accurate and reliable index than the GDP-PI for measuring gas utility inflation."

As DOER notes, this index is also more volatile than the GDP-PI, which is contrary to one of the Department's stated objectives for selecting an inflation measure. Therefore, the PPI-NG is not appropriate as an inflation measure because it: measures outputs rather than inputs; measures only a subset of outputs rather than all gas distribution output; is not available regionally, which is the appropriate inflation measure in any PBR plan for Boston Gas; is unlikely to be available in its current form in the future; is more volatile than the GDP-PI; appears suspect in any case; is not well-understood or familiar in Massachusetts is unprecedented;

- **Response to Attorney General**

The PEG model used to support the PBR proposal is not an unduly complex "black box," as alleged by the Attorney General (Attorney General at 107). In fact, there are effectively two "models." The first calculates TFP trends and the second is an econometric gas distribution cost model. The complexity of these models is analogous to what was presented by the Company last time and most of the modeling techniques are identical. In the last proceeding, the Department did not find the models too complex to evaluate, and it considered both TFP and econometric evidence when setting the terms of the last PBR formula. In fact, in the previous case, there were two different econometric models presented: one by (current) PEG employees and another by Ernst Berndt. These models did use different techniques, and the Berndt approach was in some respects more complex than that used by PEG; nonetheless, the Department was still able to review and evaluate the models reach a decision on that evidence.

Moreover, the models are not "unduly" complex. The complexities that do exist are necessary to derive the most precise TFP estimates or to make the most valid inferences on cost function parameters and utility's cost efficiency. There are some complexities inherent in these issues, but sacrificing the complexities for the sake of "simplicity" will only lead to less precise TFP and econometric estimates. PEG's methods are grounded in the literature on how best to undertake utility TFP and cost function research. For this proceeding, PEG prepared two detailed reports detailing its methodologies (Exh. KEDNE/LRK-2 and Exh. KEDNE/LRK-3), and provided key technical details. In addition, the Company presented a "plain language" description of the econometric model, as well as every piece of data that went into the TFP calculations and econometric models. These descriptions are in comprehensive, user-friendly spreadsheets that include formulas for how key variable were calculated. The Company also provided all computer programs used to compute capital stocks and to generate TFP trends and econometric estimates. This included a version of the econometric program that added comments to show exactly where key series were calculated.

The argument that the underlying support for the PBR plan is "effectively unreviewable" this is refuted by the numerous times in the past that parties and regulators were able to review largely analogous TFP and econometric analyses when setting the terms of the last PBR plan.[77]

The Attorney General also claims that the Company has not adequately justified limiting the "analysis to 16 large northeastern gas distributors" (Attorney General at 110). This argument is mistaken for a number of reasons. First, not all 16 of the companies are large – there are a range of sizes. But more fundamentally, the sample size was amply supported. The fundamental rationale for selecting the sample, and the determination that the sample size was appropriate was explained as follows:

> The original sample was designed to balance three objectives: comprehensiveness, heterogeneity, and the cost of creating the database. Our goal was to develop the sample to be as comprehensive as possible. PEG also had the objective of ensuring that the sample included companies operating under a heterogeneous mix of business conditions. This objective was particularly important for the national sample that is used for the econometric model. As I discussed in both written and oral testimony, sample heterogeneity is valued in econometric research because it helps to improve the precision of econometric estimates.
>
> The third objective is cost, which runs counter to the other two. There are no publicly available, comprehensive databases that are sufficient to undertake rigorous TFP research, so PEG has developed its own such database over a number of years. This has required us to collect data directly from contacted companies, who are under no obligation to provide this data to us. As anyone who has ever developed a database from scratch knows, this is a very labor and time-intensive process. Building a database is costly and the objective of comprehensiveness can only be achieved by increasing cost. In practice, this means that a balance must be struck between these competing objectives.

[77] PEG's models have been reviewed on numerous occasions by the California CPUC in PBR proceedings for Southern California Gas, San Diego Gas and Electric (power distribution) and San Diego Gas and Electric (gas distribution). In all cases, the work was subject to extensive review and analysis and the basic data to the CPUC staff (without gathering it into a single comprehensive spreadsheet, as we did for the Attorney General's witness in this case). In all these cases, the CPUC's decision on the industry TFP trend was *identical* to what PEG had estimated.

> **Q. GIVEN THESE OBJECTIVES, DO YOU BELIEVE THE SAMPLE USED IN YOUR TESTIMONY IS APPROPRIATE FOR ESTIMATING TFP TRENDS FOR THE NORTHEAST GAS DISTRIBUTION INDUSTRY?**
>
> Absolutely. The Northeast sample includes nearly every major, investor-owned gas distributor in the region. At the same time, it does not focus entirely on large distributors serving major metropolitan areas. Some sample distributors serve mostly suburban and even some rural territories. Six of the nine states in the region are represented (and private gas distributors are relatively new in Maine, one of the states that is not represented). There is also a mix of company sizes, ranging from Public Service Electric and Gas (about 1.6 million customers) to Central Hudson Gas and Electric (about 60,000 customers). Lastly, the 16 sample companies provide service to more than 60% of the region's customers. This represents a high degree of coverage and comprehensiveness for the region, which PEG was able to obtain while endeavoring to contain costs. Overall, I believe the sample used in the TFP study balances the three objectives well. (p. 10, line 19- p. 11, line 24)

Not only did Dr. Kauffman fully support the appropriateness of analyzing the 16 gas distribution companies, but he also presented an analysis demonstrating that the cost-benefit ratio would decline significantly if the sample size was expanded.

The Attorney General also claims that there is no evidence that gas distribution productivity growth is different in the Northeast than in the rest of the country (Attorney General at 110). This contention also is without merit.

In D.P.U. 96-50, the Department accepted a regional definition of the gas distribution industry. In this case, PEG examined the evidence the Department used to reach this conclusion and undertook similar analysis as part of its studies. It found that the evidence the Department used in D.P.U. 96-50 to support a regional definition of the gas distribution industry remains true. The decision to use a regional definition of the gas distribution industry, and the rationale on which it is based, are therefore both in keeping with Department precedent.[78]

The Attorney General also argues that the differences between the gas industry and the total business sector do not indicate that gas costs will increase faster than output prices of the business sector (Attorney General at 110). In fact, there is substantial evidence that this is true; estimated TFP differential for 1990-2000 was –0.45 percent, and when PEG was asked to update this for the 1984-2001 period, the estimated differential was –0.43 percent. This is very clear evidence that there are persistent differences in TFP growth between the gas industry and the economy, and the difference in TFP trends between the two is in fact quite stable.

The Attorney General states that the 1990-2000 sample period did not correspond ”perfectly” to the business cycle (Attorney General at 110). This is an impossible standard to satisfy because the National Bureau of Economic Research (NBER) dates business cycles beginning with a specific month, while the TFP trends measured by the BLS are only computed annually. Thus, these series can't be matched perfectly. However, the 1990-2000 business cycle is about as close to a perfect match as is practical because NBER dates the "peak" of the previous business cycle as July 1990, The economy then went into a recession that ended in March 1991 and then began to expand again, the expansion was robust through the first half of 2000, at which point growth declined dramatically (although it did not go negative until early 2001); that is, from Jan-

[78] Dr. Kaufman also discussed other factors that could cause TFP growth to differ between regions in his rebuttal testimony. Contrary to Ms. Smith's assertion that the factors affecting regional TFP growth do not have regional characteristics, economies of scale do depend on regional economic and output growth. In response to RR DTE-124, PEG also provided BEA data demonstrating that economic growth in 1990-2001 was much slower in the Northeast than the nation as a whole and, all else equal, this will lead to less output growth, realization of scale economies and thereby TFP growth.

June 2000, real GDP grew at an annualized rate of 3.7 percent; beginning in July 2000, GDP growth for the remainder of 2000 was an annualized 0.85 percent (GDP first declined in the first quarter of 2001). Therefore, the July 1990 through July 2000 period is very close to a "peak to peak" business cycle, since the economy grew at less than a 1 percent rate after July 2000 until 2001, when the expansion officially ended.

The Attorney General alleges that the larges single problem is the estimation of capital cost, which, he states, suffers from numerous inaccuracies (although the only one mentioned is the "vintaging" of the 1983 benchmark capital stock) (Attorney General at 111). Dr. Kaufmann's rebuttal testimony addressed this and showed, definitively and unambiguously, that this is not a problem:[79]

> Ms. Smith apparently believes the TFP and econometric research is flawed because it does not properly value old capital assets. Ms. Smith apparently believes costs would be higher if these assets were properly valued. All else equal, this would lead to relatively greater cost increases for distributors with a more aged capital stock. Ms. Smith believes these distributors are primarily in the Northeast. Therefore, Ms. Smith believes that my valuation of the benchmark capital stock leads to costs for the Northeast gas distributors that are systematically understated relative to the national sample, and this systematic understatement is not reflected in any other variables in the cost model.
>
> Including the Northeast dummy variable in the econometric model was not motivated by concerns over the benchmark capital stock, but the coefficient on this variable sheds light on this issue. If the benchmark capital stock is systematically undervalued for Northeast distributors, a Northeast dummy variable would have a negative and statistically significant coefficient. In fact, the opposite proved to be the case in every instance when a Northeast dummy variable was investigated. This is definitive evidence that Ms. Smith's hypothesis about the benchmark capital stock is not correct.
>
> This is a testable hypothesis. In an econometric cost model, if something is systematically affecting the costs of a subset of companies in the sample

79 Perhaps, one reason for the Attorney General's confusion on this point is that Ms. Smith neglects depreciation and the role this plays in determining an economic valuation for the capital stock.

> and is not captured by other variables in the model, you can estimate the impact of this systematic cost influence through a dummy variable. Ms. Smith contends that Northeast gas distribution costs are being systematically understated relative to the nation because of problems with the valuation of the benchmark capital stock. If this is true, then a dummy variable applied only to Northeast gas distributors would measure this systematic cost influence. Because Ms. Smith believes this factor tends to reduce costs for Northeast gas distributors, if her hypothesis was true, the coefficient on this variable would be negative.
>
> My econometric cost model did include a Northeast dummy variable. However, the coefficient on this variable was *positive* and statistically significant. As explained in my response to Information Request AG-12-17, the coefficient on the Northeast dummy was positive in every econometric run in which it was included. This was true even when we included other variables in the model, like frost depth, that could be expected to impact costs in the region. The frost depth coefficient was in fact positive when the Northeast dummy was not included in the cost model, but it became insignificant when the Northeast dummy was included. In other words, the positive coefficient on the Northeast dummy variable was robust and dominated other factors that could affect costs for the region.

In her surrebuttal testimony, Ms. Smith seemed to agree with the general tenor of this analysis, but averred that maybe the effect of the capital stock problems would only be to make the Northeast dummy coefficient lower rather than negative since, apparently, other factors specific to the Northeast could swamp this effect. However, this conclusion is not reasonable if the regression also includes other factors that would affect costs in the Northeast, such as frost depth; in such a regression, you would expect the variable reflecting the more measurable regional factors (like frost depth) to reflect these factors and therefore be positive, while the other reflecting the purported unmeasured but systematic bias to be captured by the dummy variable, and therefore be negative if Ms. Smith's hypothesis is correct. However, as the testimony above indicates, in every case where both frost depth and the Northeast dummy were included, the Northeast dummy was positive and significant and frost depth was insignificant (although frost depth was positive and significant in regressions where the Northeast dummy was not included). This further undercuts Ms. Smith's hypothesis and indicates that there is no systematic downward bias in the capital cost measure or TFP trend.

The Attorney General argues that the econometric study is flawed because it does not include a number of variables that probably influence cost and the absence of these variables is likely to make Boston Gas appear a more efficient performer (Attorney General at 112). The Attorney General, however, fails to mention any excluded variable or point to any analysis or evidence supporting the view that the absence of any such variables tends to make Boston Gas's performance better. In fact, this claim is refuted by the record in this case.

In addition to the original cost model presented in direct testimony, PEG produced regression results for 34 alternative models (24 presented in Exh. AG-16-8; five in Exh. AG-9-2; and one each in Exh. AG-18-1, Exh. AG-30-6, Exh. AG-30-20, Exh. AG-31-8, and RR-DTE-123). All told, these models examined 16 other variables, including five variables suggested by the Attorney General, as well as an alternative cost specification that allocated payroll taxes to labor costs rather than capital stocks. In *all* of these alternate models, Boston Gas was a superior cost performer, the coefficient on the Northeast dummy was positive and significant, and the coefficient on the PBR dummy was about –0.3 percent (coefficients on nearly every other variable included in the original model were also very stable). These are therefore extremely robust results, since they apply under a wide variety of alternate econometric specifications. These results also have direct implications for the Company's proposal, especially the appropriateness of a Northeast definition of the gas distribution industry and the proposed value of the consumer dividend. The evidence in this case therefore amply supports the reasonableness of the econometric estimates and their implications for the X factor; the AG presents no evidence or credible arguments to the contrary.

The Attorney General's claim that lower taxes are making Boston Gas look efficient (Attorney General at 112) is also refuted by record evidence:

> Although Ms. Smith is correct that taxes are not under a utility's control and econometric cost models should control for them, PEG's model does so because one of the independent variables in this model is the capital service price. Taxes are a component of this capital service price. This is apparent in equation (13) and the subsequent discussion in Exhibit KEDNE/LRK-2. Because our model includes a "right hand side" variable that captures the actual taxes paid by the utility in each year, the coefficient on this variable reflects the impact of taxes on gas distribution cost. Moreover, when cost predictions are made, each company's actual capital service prices are used to generate predictions. These capital service prices reflect the impact of each company's actual tax payments, so cost predictions are also tailored to the company's actual taxes paid. Because of these factors, the issue that Ms. Smith describes is not a problem in our model and is not distorting our cost predictions.

Thus, the Attorney General's argument on the effect of taxes should be dismissed.

Accordingly, the Attorney General's criticism of the Company's PBR plan are unpersuasive and should be rejected by the Department. All information needed to review plan has been provided and the plan and its supporting studies are reviewable, consistent with Department policies and should be approved.

VI. OTHER PROPOSALS

A. PENSION MECHANISM

1. Cost of Equity Issues

The Attorney General argues that if the Department were to approve the Company's proposal for a pension/PBOP reconciliation mechanism, the Department should reduce the Company's authorized return on common equity be reduced by 50 basis points (Attorney General Initial Brief at 44-45). However, in summary, the Attorney General's argument that the reconciliation mechanism will decrease shareholder risk is directly refuted by the record evidence of the cost of equity expert witness, Mr. Moul, who testified that the approval of the Company's pension mechanism will only maintain the *status quo* (Exh. KEDNE/PRM-4, at 3). As discussed below, if the Department were to allow the Attorney General's proposal, the Company's risk would actually increase as a reaction to a lowered rate of return that *removes* a risk premium for pensions where none now exists.

2. Establishment of Reconciling Mechanism

The Attorney General contends that the Company has not shown that its proposal is needed to avoid financial impairment (Attorney General Initial Brief at 45-47). According to the Attorney General, the Company has not demonstrated the volatility of pension and PBOP expense, nor why pension costs should be treated any differently than other expenses that are included in the Company's base rate revenue requirement (id.). As described below, the Attorney General's contentions are both factually erroneous and misstate the standard by which the Department traditionally considers the implementation of reconciling rate mechanisms.[80]

The establishment of reconciliation mechanisms is not a new concept in utility regulation or for the Department. More than 25 years ago, the Supreme Judicial Court ("SJC") considered the purpose of cost-adjustment clauses, and stated the advantages that

80 The Attorney General implies that "financial impairment" is the exclusive standard by which the Department considers proposals for reconciliation mechanisms. This is a red herring since, as described below, the Department's ratemaking standard for such mechanisms (as approved by the Supreme Judicial Court), does not focus on a finding of financial impairment to a company.

such clauses provide by reconciliation of costs outside the calculation of traditional base rates.

> Rate proceedings have been notoriously slow as well as expensive. Therefore the demand arose to build into the rates, provisions by which increases in certain costs to the utilities (and, to be fair, decreases as well) would in accordance with formula[e] be automatically passed on to the consumers as fluctuations of the charges to them, without the burden and expense to utilities – which would ultimately fall upon consumers – of instituting and carrying out separate rate proceedings to justify the varying charges.

Consumers Organization for Fair Energy Equality v. Department of Public Utilities, 368 Mass. 599, 606 (1975). The SJC reasoned that automatic adjustment held particular appeal "where the utility had only minimal bargaining power about the particular items of cost (e.g., a gas company purchasing natural gas from a supplier whose rates were fixed by the Federal Power Commission) . . ." Id.

Similarly, the Attorney General has previously recognized the benefits of adopting reconciliation mechanisms. According to the Attorney General, the characteristics of utility costs included in reconciliation adjustment mechanisms are those that:

> (1) are a significant part of a utility's cost of doing business; (2) vary significantly over relatively short time intervals; and (3) are substantially not within a utility's control.

Bay State Gas Company, D.P.U. 94-16, at 41 (1994).

The Attorney General's stated criteria for the use of a reconciliation mechanism, as described in Bay State Gas Company, D.P.U. 94-16 (1994), are similar to the criteria stated by the Department when it first established a cost-of-gas-adjustment mechanism for pipeline gas costs several years after interstate pipelines were first constructed to serve New England. Worcester Gas Light Company, 9 P.U.R. 3d 152 (1955) ("Worcester"). In Worcester, the Department stated that the principal reasons it allowed such an adjustment clause was the realization that "fuel prices were and are relatively volatile" and that such fuel costs represented a substantial cost. Id. at 155. A further consideration offered by the Department was the fact that "a relatively slight increase in the cost per Mcf of purchased gas would, even after taxes, materially affect the companies' net earnings." Id. In addition, the Department consideration in favor of approving the adjustment clause was attributable to the generic effect such costs might have on other utilities in the Commonwealth. The approval of the reconciliation mechanism would therefore avoid substantial cost and delay. The Department would otherwise have had to engage itself in:

> a very long and protracted series of rate hearings occupying a substantial length of time, involving substantial expense to both the companies and to the [C]ommonwealth and orders in which would necessarily, unless they were all issued at one time, prejudice one company as against another. It does not seem to us that either good regulation or common sense requires this result . . .

Id. at 156.

The Attorney General's stated criteria for the use of a reconciliation mechanism are also similar to the criteria stated by the Department in establishing a mechanism for the recovery of cleanup expenses relating to manufactured gas wastes, which were expected to be extraordinary in nature and amount. See, Manufactured Gas Site Cleanup, D.P.U. 89-161, at 52 (1990). In that case, the Department found that:

> [C]leanup expenses relating to manufactured gas wastes can reasonably be predicted to recur over the next several years. Unlike rent, wages or other periodically recurring expenses, it is not possible to derive a representative level of cost for MGP cleanup activities because the precise amount of the

> expense and its periodicity are subject to significant uncertainties, largely outside the control of the companies.

D.P.U. 89-161, at 52.

Thus, the factors that the Department considers in determining whether an expense category should be recovered as part as a reconciliation mechanism include the financial impact of the expense on the company (including the size and volatility of the cost), the degree to which the Company has to opportunity to control the cost category and whether approval of a separate adjustment clause will avoid otherwise unnecessary general rate proceedings. As described below, the Company has established on the record in this case the presence of all factors that would justify the approval of the proposed mechanism.

The level of pension expense that the Company is required to recognize in any given year is a function of accounting requirements, and not of the Company's own actions (Exh. KEDNE/JFB-1, at 30-31). The record shows that the pension and PBOP expense recognized by the Company results from a calculation that is prescribed by accounting requirements, which are designed to reflect, among other things, the actuarial determination of benefits to current and former employees, the level of funds presently in the trust fund, projections of discount rates and return on plan assets, all of which are largely outside of the control of the Company (id. at 30-32; Tr. 13, at 1677).

The magnitude and volatility of the level of pension expense and funding is also established on the record.

> In this particular proceeding, the pension increase that we've asked for accounts for approximately 27 percent of the company's revenue deficiency. The second thing is that pension costs can vary significantly over relatively short time periods. The company's pension expense in the year 2000 was a million dollars -- excuse me; in 2001, it was a million dollars. In 2002, it was six million dollars, and this year it's projected to

> be seventeen million dollars. So those costs can vary significantly over relatively short time periods.

Tr. 13, at 1676-1677. While the Company has been recovering in rates only $1.7 million per year since 1996 for pension costs, the Company's cash contributions were $19 million and $44.5 million for 2001 and 2002, respectively (Exh. KEDNE/JFB-1, at 34).

The proposed reconciliation mechanism will ease the impact of the volatility of pension and PBOP expenses for the Company and its customers. For customers, the mechanism will reconcile the costs and revenues so that customers pay only the amounts necessary for the Company to fulfill its pension and PBOP obligations. Rather than large and "permanent" changes in cost recovery established through general rate cases, the amortization of the difference between the SFAS expense and the amount being collected in rates systematically phases-in rate changes annually. Rates in the future will rise and fall more gradually and with certainty, thus reducing rate volatility and protecting customers from overpaying. The Company's earnings and equity are protected from the volatile swings in financial markets that cause large changes in earnings and charges to equity, as are mandated by accounting rules. The implementation of a reconciling rate mechanism will permit the Company to continue to defer expenses as regulatory assets, thus eliminating the impact.

The Attorney General argues that the Company should not recover carrying charges on the prepaid pension balance (Attorney General Initial Brief at 47-48). According to the Attorney General, the Department should not allow the recovery of carrying charges on the net prepaid pension and PBOP balance because it would be inconsistent with Department precedent (id. at 47). In addition, the Attorney General alleges that the Company's proposal does not require it to make any contributions to its pension or PBOP trust funds (id. at 47-48). For the following reasons, the Attorney General's arguments are without merit.

The application of carrying charges is designed to compensate both the Company and customers for the time-value of money relating to collection and payment of the pension and PBOP expenses (Exh. KEDNE/JFP-1, at 41).[81] The prepaid pension amount carried on the Company's books is created as a result of the Company making cash contributions to its pension trust that are in excess of the accounting expense that is recorded on the Company's books (i.e., the Company cannot expense amounts on its books greater than the amount calculated pursuant to SFAS 87) (id., at 41-42). The reason such contributions are made in excess (i.e., prepaid) of the booked amount for SFAS 87 is because ERISA/IRS rules permit different amounts to be contributed to the trusts on a tax-deductible basis than amounts booked according to SFAS 87 and 106.

The Attorney General mistakenly attacks the carrying-charge calculation based on the argument that "the Company was not measuring correctly the cash required by investors to cover the difference between the actual recovery of pension expense in rates and cash disbursements to the pension plan" (Attorney General Initial Brief at 47). However, this is precisely what the formula does. The annual adjustment formula includes a carrying charge factor that is applied to the unamortized balances remaining from the deferred pension expense amount and prepaid amounts, which occur when the

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81 FERC precedent has also permitted carrying charges on prepaid pension expenses. Cities of Greenwood and Seneca, South Carolina v. Duke Power Company, 77 FERC ¶ 63,017 at Item 14 (Initial Decision) (1996). Even though such prepayments were not required by law, the decision allows carrying charges because the prepayments were made for the purpose of maximizing the tax benefits and minimizing current pension expenses. "As a result of these prepayments, Duke has lowered its current and ongoing O&M expenses in a manner similar to a utility making capital investments" (id.).

Company has paid funds into the pension/PBOP plans that are greater than amounts required by SFAS 87 and SFAS 106. Applying the carrying charges to these two elements compensates the Company or its customers for the time value of money for the difference between: (a) the amounts paid into the trust funds by the Company; and (b) the amounts collected in rates from customers. Thus, both the Company and its customers are "made whole" if there is a timing difference between the collection of revenues in rates from customers and the cash contributions made by the Company to the trust funds.

In many orders over the years, the Department indicated that it is appropriate for companies to make cash contributions to its pension and PBOP funds equal to the maximum allowable tax deductible amount (i.e., regardless of whether such an amount exceeded SFAS 87 "booked" amounts):

> The Department encourages companies to take optimum advantage of the benefits attendant to the funding of PBOPs. Tax-free accumulation of assets in a trust with appropriate safeguards should ultimately result in lower over PBOP costs for ratepayers.

Cambridge Electric Light Company, D.P.U. 92-250, at 54 (1993). See also Bay State Gas Company, D.P.U. 92-111, at 226 (1992) and Massachusetts Electric Company, D.P.U. 92-78, at 83 (1992) (the Department finds that funding at levels equal to the maximum allowable tax deductible amount strikes the best balance between the interests of ratepayers and shareholders).

In fact, the Department previously has allowed companies to defer with carrying charges at the allowed rate of return the difference between the amount of PBOP expense recovered in rates and amounts actually funded. Cambridge Electric Light Company, D.T.E. 92-250, at 54 (1993) ("The Company may defer the difference between the amount recovered in rates and the tax-deductible amount it actually funds, plus carrying costs based on the allowed rate of return in this case, for consideration in the Company's next rate case"). The Department approved the same treatment for deferred pension costs in Boston Edison Company, D.P.U. 92-92 (1992). Thus, the proposed application of carrying charges is fair to the Company and its customers and is consistent with Department (and FERC) precedent.

The Attorney General's charge that that the Company's proposal does not require it to make any contributions to its pension or PBOP trust funds is also without merit. Although the Company's proposed mechanism does not include a requirement to make actual contributions, ERISA law, regulations and IRS rules impose such requirements. Moreover, there are real and practical incentives to make the contributions each year to the maximum extent allowed by law. ERISA and the IRS impose legal minimum contribution requirements based on section 412 of the IRS Code. Customers benefit through tax-free returns, thereby lowering future expenses and future costs to customers. The Company has a strong incentive to contribute up to the maximum allowable tax deductible contribution to its pension and PBOP trust each year to capture the maximum tax benefits associated with making such contributions.

The requirement that the Company use the funds obtained from customers through base rates or reconciliation mechanisms for the purpose they are designed for is no different from any other Company expense. Although it is conceivable that the Company could use this money for other purposes, the Company and its corporate officers ultimately must bear their legal and fiduciary obligation to the Company's shareholders, employees and customers. Customers will pay on a going-forward basis no more than the amounts required to fulfill the Company's current pension and PBOP obligations and the prepaid amounts not yet expensed. Accordingly, the Attorney General's suggestion that the reconciliation mechanism may somehow be improperly diverted is without merit.

B. The Company's Proposed Weather Stabilization Clause Will Promote Rate Continuity By Stabilizing Customer Bills During The Winter Billing Cycle

Mr. Silvestrini demonstrated that the Company's proposed WSC will minimize fluctuations in customer bills due to weather volatility, and thus, promote rate continuity during the months of November through April (Exh. KEDNE/ALS-1, at 31-34; Exh. AG-19-28; Exh. KEDNE/ALS-6, Tr. 3, at 267-268, 272; RR-DTE-3).[82] Mr. Silvestrini testified that the Company's revenue requirement, in terms of both the underlying costs and revenues, is recovered based on "normalized" sales volumes, or the sales volumes projected under normal weather conditions. Therefore, when actual weather differs from normal weather: (1) the Company's actual firm sales volumes will differ from the billing determinants used to design distribution rates, thereby causing the Company to recover a greater or lesser amount of revenue, depending on whether it is warmer or colder than normal; and (2) the volumes of gas consumed by customers are affected (Exh. KEDNE-ALS-1, at 31).

Mr. Silvestrini further testified that, as a result, customers experience increases in their total bills when weather is colder than normal and the Company recovers a greater amount of revenue (id. at 31-32). Conversely, when weather is warmer than normal and

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[82] The WSC adjustment would apply to rate classes R-1, R-2, R-3, R-4, G-41, G-42, G-43, G-44, G-51, G-52, G-53 and G-54 during the peak period November through March (Exh. KEDNE/ALS-1, at 34; Tr. 3, at 266).

customer consumption is lower than expected, customers have relatively smaller bills and the Company recovers a lower amount of revenue (id. at 32). Mr. Silvestrini noted that this dynamic is exacerbated because the Company's rate-design methodology utilizes: (1) embedded cost-allocation formulas that assign 65% of non-gas costs and revenues to the peak period; and (2) a marginal-cost/rate design methodology that assigns 18% of the revenue recovery to the tailblock (id.; Exh. D.T.E. 03-22). Accordingly, the combination of assigning a large portion of costs to the peak period, and recovering those costs in the variable portion (tailblock) of the distribution rate, makes both net revenues and customer bills particularly sensitive to weather (Exh. KEDNE/ALS-1, at 32).

In order to mitigate this sensitivity, the Company proposed to implement a WSC whereby in each billing cycle during the peak period November through April the Company will adjust customer bills to account for any variation in weather that deviates by more than 2% of normal[83] during that cycle (id.; Exh. KEDNE/ALS-6; Tr. 3, at 274).[84] Mr. Silvestrini outlined the specific methodology for calculating the adjustment, which would be based on the percentage difference between actual and normal degree days during the billing cycle (Exh. KEDNE/ALS-1, at 33; Exh. D.T.E. 3-27 (rev); RR-DTE-6). The adjustment would be made to the tailblock rate and applied to all therm sales for that billing period (Tr. 3, at 278; Tr. 4, at 385).

83 For purposes of the WSC, the Company used the most recent 20-year average of degree-days for the Company's service territory, i.e., the 20-year period 1983 through 2002, inclusive (Exh. KEDNE/ALS-1, at 32-33; Tr. 4, at 414). However, the Company noted that, if the Department approves the Company's PBR proposal, it would willing to update the definition of "normal weather" to use a 20-year rolling average when calculating the factors described in the pro forma compliance filing for its WSC (RR-DTE-8; Tr. 24, at 3256).

84 During evidentiary hearings, Mr. Silvestrini proposed revising the language of the Weather-Normalization Adjustment WA Formula in order to eliminate an ambiguity regarding its application (Tr. 4, at 387).

Mr. Silvestrini testified that applying the adjustment to the tailblock rate is most appropriate because the Company's rates are designed such that the tailblock reflects the marginal costs of serving the customer (id.). Because customer bills would be adjusted on a real-time basis, it would provide timely relief from weather variability affecting customer bills in the winter period (Exh. KEDNE/ALS-1, at 33).[85] Accordingly, the Company has demonstrated that the WSC will minimize fluctuations in customer bills due to weather volatility, and thus, promote rate continuity during the winter period, consistent with the goals of the Department. Therefore, the Department should approve the Company's WSC for application during the Rate Plan.

⇨ Response to the Attorney General

The Attorney General alleges that "[a]lthough the Company claims that [the Weather Stabilization Clause] will protect ratepayers from the volatility in their bills resulting from unusual cold weather . . . , the end result will be the stabilization of the Company's revenues" (Attorney General at 94). The Attorney General goes on to state that the Department has rejected Weather Stabilization Clauses ("WSC") for four reasons. The mechanisms "(1) do not equitably share the potential risks and benefits between ratepayers and shareholders; (2) do not respond to the increasing application of competitive market forces in the allocation of energy resources; (3) are not based on reliable weather data; and (4) they would have resulted in rates that were not just or reasonable" (Id.) The Attorney General concludes that the Company's WSC, which the

85 The Company will update the Department in its annual PBR filing regarding: (1) base load factors for each rate class; (2) heating increments for each rate class; and (3) tailblock margin for each rate class (Exh. KEDNE/ALS-1, at 34; Exh. DTE-3-23; Tr. 4, at 389-390).

Company calls a Weather Normalization Clause ("WNC"), "suffers from the same defects the Department noted a decade ago.

The Company's WNC would benefit customers. As Company witness Mr. Bodanza explained "when weather is colder than normal, customers face a 'double burden' since their bills are rising due to increased consumption, and they are likely to also experience rising commodity costs." Exhibit KEDNE/JFB-1 at 45. Moreover, the WNC is not being proposed to stabilize the Company's revenues, because the Company has other mechanisms in place to accomplish this objective. For example, the Company enters into financial arrangements that remove the risk of weather volatility. Exh. KEDNE/JFB-1, at 46; Tr. at 2909. However, customers generally do not have this same ability. Therefore, a WNC would provide the Company the same benefit it already obtains in the marketplace today, but it would provide customers an important benefit they otherwise could not obtain. The only benefit to the Company is increased customer satisfaction. Tr. at 2915.

As the Attorney General acknowledges, the precedents he sites are more than a decade old (Attorney General at 94). Bay State Gas Company, D.P.U. 92-111; Berkshire Gas Company, D.P.U. 92-210. At that time, the financial arrangements to avoid the risk of weather volatility were simply not available. Tr. at 1940. Utilities, such as the Company, now are in the position to stabilize their earnings against weather volatility on their own. Since any WNC is now needed only for the benefit of customers, the allocation of benefits that the Department was concerned about in D.P.U. 92-111 and D.P.U. 92-210 is no longer an issue.

For the same reason, it is no longer relevant to consider whether the Company's WNC should require an adjustment to the Department's allowed equity return for the Company. As Company witness Mr. Moul has explained, the companies in the barometer group that he has relied on to estimate the Company's cost of equity, a group whose composition is not in dispute in this proceeding, either have WNCs already or are expected by investors to take advantage of the same type of financial instruments the Company does to remove the risk of weather volatility. Tr. at 1937-38. If the Company differed from Mr. Moul's barometer group in not being able to implement a WNC or to access weather insurance in the marketplace, then the Company's cost of common equity would have to be adjusted to be higher than that of the barometer group. However, this is not the case. Weather risk, as of the past few years, has been removed from gas utilities, and therefore, from consideration in a gas utility's cost of equity capital.

The Attorney General misstates the Department's previous position on the impact of WNCs on competition. Rather than "reject[ing]' WNC proposals "because they represent a movement back to cost-based regulation and away from market based regualtions," as the Attorney General asserts at page 95 of his brief, the Department in Bay State, at D.P.U. 92-111, at 58 and Berkshire at 196 raised only a "concern" andhat competitive market concern is readily addressed. The Company's proposed WNC is solely on the distribution charge, not the commodity charge. Tr. at 2908. The movement from cost-based regulation to market-based regulation affects only gas commodity; the distribution service remains cost-based. To the extent that these competitive concerns may involve the competition between natural gas and heating oil (a concern not raised by the Department but by the Attorney General in Bay State, D.P.U. 92-111, at 45), the price adjustments of the WNC are short-term and expected to cancel out over time. The choices of the firm heating customers for which the WNC will apply involve long-term investments in heating equipment and are not affected by month-to-month price adjustments. Moreover, there is no reason that heating oil dealers could not offer a WNC of their own-they are free to do so without seeking regulatory approval. Therefore, the Company's proposed WNC raises no obstacle to the movement from cost-based regulation to market-based regulation.[86]

The Attorney General further argues that the Company's proposed WNC should be rejected because it is not based on reliable weather data. In support of this argument he cites to the fact that the Company's WNC uses normal degree day information from a single location, Logan International Airport ("LIA"), while in actuality the Company's customers experience different weather depending upon their location within the service territory (AG Brief at 96). What the Attorney General fails to recognize is that the WNC is not intended to measure absolute differences in degree day weather experienced by each individual customer. Rather, the WNC measures the deviation of actual weather from a defined normal set of degree days to determine the appropriate percentage adjustment for all customers throughout the service territory. Thus, the absolute difference in degree days experienced by a customer at point A as compared to a customer at point B is irrelevent. What is important is that changes in weather relative to normal measured at point A be highly correlated with changes in weather relative to normal measured at point B. Once a sufficient correlation is established, it is then

[86] Furthermore, there is no indication on the record nor reason to believe that a utility's incentive to minimize operating and maintenance costs would be diminished by the Company's proposed WNC. The revenue impact from the happenstance of weather-driven throughput changes has no relationship to efficiency of operation.

appropriate to infer that a certain percentage deviation from normal weather in one location, will accurately reflect the percentage change from normal weather experienced by all customers regardless of location within the service territory. The Company uses the LIA weather station data to represent weather conditions in the Company's service territory because LIA is geographically centered within the Company's service territory, and also because of the high correlation between the heating degree day values for LIA and those in other areas of the service territory. AG-19-31. Use of LIA weather data in this manner is consistent with the Department's order in the Company's most recent Long Range Resource and Requirements Plan. KeySpan Energy Delivery New England, D.T.E. 01-105, at 5 (2003).[87]

The Attorney General next argues that the Department should not allow a WSC adjustment for non-heating customers because their gas use is not weather sensitive and that customer confusion and dissatisfaction could result from a realization by non-heating customers that their bills vary with weather. AG Brief at 97. The Company agrees that a well-designed WNC should apply only to heat-sensitive rate classes. In this case, the Company has provided evidence that sendout for each of the rate classes included in the WNC is in fact temperature sensitive. Exh. DTE 2-42 and DTE 2-44. Given that customers within these rate classes are already subject to fluctuations in billing amounts based on changes in weather it is appropriate to apply the WNC to each class.

87 "KeySpan has demonstrated graphically and statistically that the LIA weather data are representative of weather conditions in the Company's service territory (cite omitted). Because the Company's current weather data are from a weather station which is centrally located within its service territory, and are based upon data sets encompassing a substantial historical period, including recent observations, the Department concludes that KeySpan's weather data appear to be accurate, reliable and appropriate for use in establishing the Company's planning standards."

Lastly, the Attorney General argues that unjust and unreasonable rates will result from the WNC because the tailblock rate proposed by the Company, and that is used in the WNC calculation, is set at marginal cost for residential customers but at a rate higher than marginal cost for commercial customers (Attorney General at 97). The Attorney General's argument is misplaced. In this case, the Company proposes to apply its WNC to the tailblock portion of the rates determined by the Department to be just and reasonable, whatever that tail block rate is ultimately determined to be. The tail block portion of the rate is the appropriate rate component to be applied to increases or decreases in customer consumption that result from colder or warmer than normal weather because the weather-sensitive portion of a customer's load is billed at the tail block rate. The finding of the Department as to what constitutes a just and reasonable rate design is not dependent on the Company's WNC proposal. Rather, the WNC will be applied to that tail block that the Department determines to be just and reasonable.

The changes in the natural gas market that have subjected consumers to significant price volatility and responsive changes in the financial markets that have provided weather insurance to entities such as LDCs but not to most consumers of natural gas. A WNC would efficiently match the complementary weather risks of the Company and its customers, concerning the distribution portion of the customer bill, enabling both to benefit from the moderation of price volatility that the Company alone currently enjoys. The Company's WNC is well designed and raises none of the concerns that have been raised with previous proposals presented before the Department.

VII. STAFFING LEVELS

A. Statutory Language

G.L. c. 164, § 1E(b) states in pertinent part that:

> In complying with the service quality standards and employee benchmarks established pursuant to this section, a distribution, transmission, or gas company that makes a performance based rating filing after the effective date of this act shall not be allowed to engage in labor displacement or reductions below staffing levels in existence on November 1, 1997, unless such are part of a collective bargaining agreement or agreements between such company and the applicable organization or organizations representing such workers, or with the approval of the department following an evidentiary hearing at which the burden shall be upon the company to demonstrate that such staffing reductions shall not adversely disrupt service quality standards as established by the department herein. Nothing in this paragraph shall prevent reduction of forces below the November 1, 1997 level through early retirement and severances negotiated with labor organizations before said date.

B. Applicability to Boston Gas

In accordance with G.L. c. 164, § 1E(b), a gas company that files a PBR plan after November 1, 1997 is not allowed to engage in labor displacement or reductions below staffing levels that were in existence on November 1, 1997, unless: (1) the staff reductions are part of collective bargaining agreements between the company and the applicable organization representing such workers; or (2) with the approval of the Department, a company has demonstrated that staff reductions will not adversely disrupt service quality from those standards that have been established by the Department. As detailed below, G.L. c. 164, § 1E(b) is not applicable to the Company because Boston Gas was subject to a PBR Plan prior to effective date of the statute, and therefore, the "staffing benchmark" established as of November 1, 1997 has no applicability to the operations of Boston Gas.

The PBR Plan for Boston Gas commenced on December 1, 1996, and therefore, any and all actions taken subsequent to that date in terms of staffing do not fall within the purview of the staffing benchmark. Because the Company was allowed under the first term of the PBR to reduce staffing levels, and the term of the PBR encompassed

November 1, 1997, the Company cannot now be held to the level in place on November 1, 1997 – the benchmark is forever inapplicable to the Company's operations. Under the Attorney General's construct, it is possible that the Company would have permissibly reduced its staffing levels below that on November 1, 1997 under a Department-approved PBR, yet be required to increase its staffing levels to be consistent with that of November 1, 1997, each time it submits an updated PBR for Department review and approval. Accordingly, the Department should reject the Attorney General's argument that G.L. c. 164, § 1E is applicable to the Company's proposal.

However, even if the Department were to find that it is applicable to Boston Gas, there are two considerations that bear against the Attorney General's arguments. First, G.L. c. 164, § 1E allows for staffing reductions that are undertaken consistent with the Company's collective bargaining agreements. As a result, any reduction in bargaining unit staffing levels from that the level in place as of November 1, 1997, were accomplished in accordance with the collective bargaining agreements executed by the Company and the relevant bargaining units.[88]

Second, the statute allows staffing reductions where a demonstration is made to the Department that the reductions are achieved without a decline in service quality. Boston Gas operates under a Department-approved service quality plan wherein the Department has established historical benchmarks that the Company must meet. Failure to adhere to those benchmarks would result in the imposition of a financial penalty on the Company. As provided for on the record, the Company has consistently met or exceeded

88 The Attorney General's argument that simply transferring employees from Boston Gas to the Service Company represents a reduction in staffing level from that of November 1, 1997 is misplaced. The employees remain in the Company's employ and the Company has not reduced those jobs.

its historical benchmarks (which, for some service quality standards, are based on ten years of data) without assuming a penalty. Thus, even if the Department determined that the Company's 2003 PBR proposal was governed under G.L. c. 164, § 1E, the Department is authorized to approve a reduction in staffing if such a reduction has not had an adverse affect on the Company's service quality and the record demonstrates that there was no such adverse affect on the Company's service quality. Accordingly, the Attorney General's argument should be rejected.

Accordingly, the Company's PBR with regard to staffing levels and service quality is consistent with the legislative mandate as contained in G.L. c. 164, § 1E, and should be approved by the Department.

Respectfully submitted,

KeySpan Energy Delivery New England
d/b/a Boston Gas Company

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